BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket No.

CONFERENCE ON PUBLIC UTILITIES' : PL04-9-000

ACQUISITION AND DISPOSITION OF :

MERCHANT GENERATION ASSETS :

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Commission Meeting Room
Federal Energy Regulatory
Commission
888 First Street, N.E.
Washington, D.C.

Thursday, June 10, 2004

The above-entitled matter came on for technical conference, pursuant to notice, at 1:05 p.m., Ms. Simler, presiding.

APPEARANCES:

JOHN HILKE, FTC

STEVE DANIEL, GDS Associates

APPEARANCES CONTINUED:

PETE DELANEY, Oklahoma Gas and Electric Company
PETER KING, CitiGroup
PETER ESPOSITO, Intergen
DAVID DeRAMUS, Partner, Bates White
JONE-LIN WANG, Cambridge Energy Research Associates
MARK COOPER, Consumer Federation of America
DIANA MOSS, American Antitrust Institute
MARJI PHILIPS, PSEG
CHRISTINE TEZAK, Schwab

P R O C E E D I N G S

(1:05 p.m.)

MS. SIMLER: Welcome to this afternoon's Conference on Public Utilities' Acquisition and Disposition of Merchant Generation Assets.

We are pleased to have two panels of distinguished speakers. Both panels have been asked to address and discuss a series of questions aimed at determining the competitive effects of vertically-integrated utilities acquiring affiliated and unaffiliated merchant generation assets.

We're going to be discussing whether the current Section 2.03 review standards need to be changed in light of changes in the industry, and we're going to be hopefully talking about remedies for horizontal and vertical market power issues and monopsony power.

The conference is going to run the same way as this morning's conference. Each panelist is going to have five to seven minutes for opening remarks, and we're going to take clarifying remarks right after that.

At the conclusion of all of the panelists' opening remarks, then we'll have Q&A from FERC Staff and from our audience. There's going to be a 15-minute break between the panels, and with all of that said, I'd like to thank the panelist and audience participants for their time and participation.

We're going to get started with the first panelist, and we're going to go in reverse order, and we're going to start with Jone-Lin Wang of CERA. Thank you.

MS. WANG: My name is Jone-Lin Wang, and I'm with Cambridge Energy Research Associates. CERA offers comprehensive research and insights on energy markets, industry dynamics, technology, politics, and investment strategy.

And over the next five minutes, I will speak about the power industry landscape and a few recent developments. The power generation business has gone through dramatic changes over the past decade.

In the mid '90s, public utilities owned more than 90 percent of total U.S. generating capacity under various cost-of-services regimes. But since then, their share has declined sharply.

CERA estimates that today the power industry has about 1,000 gigawatts of generating capacity, of which about 550 gigawatts or 55 percent, is under cost-of-service rules. The remaining 450 gigawatts, or 45 percent, is subject to varying degrees of market competition.

Of the 450 gigawatts of competitive generation, about 60 percent is owned by unregulated subsidiaries of the utility holding companies. I will now describe the transition that has occurred and few new developments.

Both public policies and perceived business opportunities drove the decline of public utilities' share in generation from over 90 percent a decade ago, to 55 percent today. The decline came about in three major ways:

First, many utilities divested themselves of existing power plants through public auctions or other sales agreements as restructuring orders or settlements. Such divestitures moved about 100 gigawatts of existing capacity into the hands of competitive generators.

Second, with the approval of the regulators, many utilities transferred power plants to their unregulated affiliates under the same corporate umbrella.

This moved another more than 100 gigawatts of capacity from the cost-of-service side to the competitive side.

Finally, during the build boom of the past five years, 75 percent of the 200 gigawatts of new capacity was built by competitive generators.

Over the past two years, the state-by-state, patchwork transition from comprehensive regulation to market competition, has lost its momentum. In addition, oversupply in generation capacity has led to financial distress for many competitive generators, sharp declines in market value of competitive generating assets, and a shift in equity valuations that now favor regulated utilities.

This has led to several new developments: First, many owners of merchant plants financed by project debt, have turned over their power plants to their lenders. This amounts to about 90 gigawatts, to date, and we expect more to come.

Second, private equity firms seeking under-valued assets, have moved in. They have bought or have made deals to buy a total of at least 23 gigawatts, to date.

We think that these firms have the appetite and capital in hand to buy more over the next 12 to 18 months. Together, these new financial players, reluctant lenders, and private equity firms now own at least 42 gigawatts or about nine percent of non-utility generation.

Over the long term, equity firms' interest in power generation is likely wane as they rotate to other industries that may appear to offer better value, while most lenders will most likely seek the earliest opportunities to exit this business.

Another new trend is that utilities are reversing their previous role as sellers of plants. Some are now buying plants from competitive generators and moving these plants to the cost-of-service side.

Their perception of better business opportunities now on the utilities' side, is a major driver of this move.

We have identified 20 such purchases over the past two years, each involving more than 100 megawatts, for a total of 10.1 gigawatts.

Among these 20 cases, ten are investor-owned utilities buying from unregulated competitive generators for a total of 4.3 gigawatts. Four are investor-owned utilities buying from their unregulated affiliates for a total of 4.3 gigawatts.

The remaining six are rural cooperatives and municipal utilities buying from competitive generators, for a total of 1.5 gigawatts. The vast majority of these purchases involve recently-built gas-fired generating plants.

Some people see utilities' purchasing competitive generating assets as anticompetitive. CERA does not think that such purchases are necessarily anticompetitive.

When a power plant is moved from the competitive side to the cost-of-service side, it does not take supply out of the market or change the demand/supply balance.

Furthermore, it does not necessarily lead to an increase in concentration, and an increase in concentration does not necessarily lead to market power.

CERA believes that all purchases of generating assets should be subject to the same scrutiny, whether the purchasers are utilities or non-utilities. Ironically, barriers to utilities' purchase of merchant plants may reduce competition for distressed generating assets, and aggravate the already fragile financial condition of the merchant generation segment.

The loss of momentum for restructuring means that the power industry will have to live with this current half-regulated, half market-based, unintended hybrid for at least the next few year and most likely longer.

The 55 percent cost-based, 45 percent competitive split in generation may shift, most likely toward cost-based, given the depressed state of the competitive business, and given Wall Street's current preference for the regulated side, but we expect only marginal shifts.

This is in part because state regulators are in the position to review utility purchases as part of comprehensive resource planning. We also see the possibility that a few years down the road, when weaknesses and problems in rate regulations are likely to resurface, the competitive side may return as the favored side, and, thus balance may shift towards more competitive generation.

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And that concludes my prepared remarks.

MS. SIMLER: Thank you. Are there any clarifying questions?

(No response.)

MS. SIMLER: Okay, we'll move on to Mr. Peter Esposito, representing Intergen.

MR. ESPOSITO: I'd like to thank you first for allowing me to come here to share my thoughts at the last minute, and I'll move on quickly to what is the context in which we're going through this exercise?

I was here yesterday and we had a lot of talk about withholding, and I would add that withholding transmission is probably just as bad or worse than withholding generation, and we ought to keep that in mind. But to bastardize the immortal words of Dorothy, Toto, I don't think we're in California anymore.

We have long-term contracts, God has stopped withholding the hydro, and those who are alleged to have withheld are no longer there or no longer dare to do so. Nor are where the Commission thought we would be in terms of open access and structured competitive markets.

Now, even the Commission has said that the 888 tariffs don't work, and they have done that both in Order 2000 and the SMD proceeding.

The old-style utilities are out there saying "I told you so," and blaming IPPs for building where there's surplus, making bad decisions and wanting a bailout.

I would say, sure, there probably were some bad decisions out there, but, for the most part, the decisions to build IPP power were rational. They built where there were dirty, old, inefficient plants, and there was load growth and they expected to be in markets where people would choose cheaper, cleaner power when they had to choose for existing load and for new load.

Now, it took a rise in gasoline prices of about a third, but car lots are now filling up with gas-guzzling SUVs and smaller, more efficient cars are in demand, and in a truly competitive environment where consumers make the decisions, and a world where gas prices have tripled, the old boilers would be surplus and not the new, efficient IPP plants.

Nonetheless, today we see tens of thousands of megawatts of old boilers running while tens of thousands of megawatts of new, clean, efficient, combined-cycle plants are sitting idle. You've got to ask why? Is this market power?

Well, we heard a lot about different market power screens yesterday, and I'd submit that the ultimate market power screen is the broadly-accepted definition of market power: Can the market participant increase prices over competitive price for a significant period of time?

And I would also submit that this test has clearly failed when those tens of thousands of megawatts of new, clean, efficient plants with six-dollar gas are sitting idle.

And when the ultimate test has clearly failed, why would we go to other screens? Well, I think there are valid reasons to go to other screens, because there might be more subtle exercises of market power that they might show up.

But what we're talking about here are huge elephants dancing on a coffee table that are trying to watch the Super Bowl. Can I overstate the case? A gentleman suggested that I make a Viagra joke, and I won't go there on this elephants on the coffee table, but you see what I'm getting at.

Well, where is this market power being exercised? Well, in the South and other areas where utilities have yet to open their markets, develop working competitive markets, by joining RTOs or otherwise, that's where the action is with the elephants.

These folks just want it t he old way, and I can respect their opinions to some extent. First, if they believe that customers really benefit from full regulation, they ought to be true to their beliefs and not keep their market closed while earning bundles in others' markets that have opened up.

Second, if they like it the old way, they ought not to be trying to benefit from having reversed the tide toward competition and bankrupting and they buying IPPs.

Another question that was asked yesterday many times, is what should the Commission do? Well, in a perfect world, we'd have a standard set of rules that applied to everyone, gave investors a sense of certainty, protected consumers, and gave entrepreneurs a reasonable opportunity to make a profit that would ultimately be tempered by competition.

SMD, that would be a great step forward, perhaps not perfect, but SMD isn't here all over the place and it's not getting there anytime soon, given the political winds in this town. It might ultimately prevail, but in time to keep many IPPs from going under, not because of bad business decisions, but because of the exercise of raw political power and slowed-down regulatory initiatives.

The IPPs don't need oxygen; they need to get the boots of those that would like to use their market power to strangle them off their necks, and we need to act now.

What kind of action do we need? Pragmatic action. I say, respect the wishes of those who like the regulated mode, those utilities and their PSEs. Tell them if you want to be regulated, will give you regulated rates anywhere you do business, and that includes affiliates and subsidiaries.

But don't try to play both sides of the fence or to benefit from exerting your market power against your potential competitors. And, by the way, when you're selling in your service territory, we'll give you the benefit of market rates there, because we'll trust your PSC will keep you from making too much, and if they don't, then their customers will scream to them and that will get it fixed.

What, exactly, does this mean? It means revoking the market-based rates of those who have not yet opened up their systems to competition. If these utilities see the light and want to open their markets up to competition later, they can come in, petition the FERC for market-based rates, and show that they have opened their markets.

Now, doesn't that get us right back to SMD and RTOs? I would submit that we don't have time to wait for that, but we should accept other methods of opening markets that are effective.

And I think you can do that pretty much on a case-by-case basis, at first; look for things like divestiture of generation, economic dispatch programs, effective RFP programs -- and I mean not just hourly markets -- transmission being built out or simply being available, because there's excess transmission. That may be the case somewhere.

Allowing others to target or actually build out transmission improvements, when IPPs come into the system along an interconnect, they're told what the improvements have to be. They aren't given the opportunity to say, well, we'd rather have it there, and if we're going to pay, put our money there.

And, as a result, you often get a case where the utilities take your money, build some transmission, but it doesn't help you move your power off the system to other market; it's helps you move your power to their markets only, and they buy it on their terms.

I might also include auctioning off wholesale load as they do in New Jersey and Maine and other places; retail access; designating IPPs as network resources, so they can get transmission in a situation, perhaps in combination with economic dispatch.

It means retiring old plants. Any of these or a combination of these may get you to the point where you actually are taking care of market power issues. I'm sure there are more.

I think that, over time, what would happen is, you would create a series of templates or safe harbors that people could look to to say, okay, I'm not ready to go to an RTO, my PSC is not ready for me to go to an RTO, but I can do this, this, and this, and I think we'll get there and everybody can be happy, and the consumers will ultimately benefit.

And as to those who want to pick up IPP assets that are distressed in the meantime, the Commission should also do something pragmatic by using its conditioning authority. It should say that if you want to pick up more generation, increase your generation market power, we ought to do something about it to counter it.

That can be, again, a variety of different mechanisms to counter that increase in market power, but there ought to be something there, and the Commission has, certainly, conditioning authority. They used it ten years or so ago to start open access to begin with.

Let me preempt a question here, if I may, and that is, how can the Commission take away market-based rate approval for an affiliate that is operating in a competitive environment? I think if we look to the beginnings of open access when the hydro power in Canada wanted to come down, we said to them, the Commission said to them, reciprocity. Open your markets; we'll open ours, and I think that that same pragmatic approach can work here.

I started with practical approach and where we are now, and let me finish with one: This is all about consumers. When those 14,000 heat rate boilers run and the 7,000 heat rate boilers sit idle, consumers pay for the difference power costs, generally under fuel adjustment clauses.

I've had occasion to look at what consumers have paid under these clauses back in the mid-1990s, versus last year, which is the most current year for the Form 1s, which is the basis of where I get my information from. And there are utilities that are relatively small utilities -- I won't mention any names at this point -- whose fuel adjustment clauses have swung $250 million per year between '96 and 2003.

That's real money for consumers. That's not an unusual number at all, by the way and those are the ones they have to decipher. Some of the Form 1s are extremely difficult to decipher, and I would suggest that the Commission take a look at these, and state commissions also look at these.

This creates an incredible burden on consumers when utilities don't buy from IPPs that are sitting there ready to sell. There's an exercise of market power of immense proportions, that needs to be remedied now, at $5 and $6 and $7 gas prices. Thank you.

MS. SIMLER: Thanks, Peter. Mr. Perter Kind, with Citigroup. Thank you.

MR. KIND: Thank you and good afternoon, everyone. My name is Peter Kind and I am presently a Managing Director and co-head of Citigroup's North American Global Power Group.

Citigroup, as you probably all know, is a worldwide global financial institution. Within our North American Investment Banking Power Group, our clients include both investor-owned utilities and merchant power generation companies.

By way of background, I've got over 22 years of investment banking experience. I have an MBA in Finance, a Bachelor's Degree in Accounting, and I was previously a CPA.

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The purpose of my remarks today are to provide an investor perspective of the competitive impact of acquisition of merchant generation assets by utilities and to comment on the capital formation challenges for power generation assets in the future.

By way of an overview, from an investor perspective, the utility acquisition of merchant generation assets is not the source of challenges facing the merchant power industry today. The source of merchant power industry challenges can be attributed to a surplus of generation capacity in many regions of the United States and the inherent conflicts of a hybrid regulated, competitive wholesale market where each geographic region has a different business model.

The purchase of merchant power assets by utilities will not alter these factors in a non-competitive way. From an investor perspective, which is where I live, precluding utility purchases of merchant power assets will reduce the universe of potential investors in such assets, and thus competition will decrease for investors seeking to optimize recovery of their investment.

I know the Commission asked to speak about trends. Let me just start off by moving to 1998 and saying that by the year 1998 -- and we had a speaker before speak to how the industry developed prior to then -- a combination of power industry restructuring and expected growth in demand for power and significant capital availability, sparked a boom in power plant development.

We heard about approximately 200 gigawatts that were constructed in 1998 through 2003, which is approximately a 20-percent increase in installed U.S. power generation capacity.

This power plant building boom resulted in capacity exceeding near-term market demand, and, as a result, contributed to lower prices and financial distress for many merchant power plant owners and investors.

Market expectations for the recovery of viable profitability from merchant power plants is unclear, but power markets are expected to remain weak for several years to come.

I'd now like to move to a perspective on the various investors included in today's question, and I will start off with the utility perspective. The utilities with an obligation to serve, seek security as to their source of electricity supply and the price of that supply.

And, as I see, it they simply have three choices: They can build new power plants, they can acquire existing plants, or they can, three, contract for power through contracts and have a long-term power purchase agreement.

Let me speak to those three points very quickly. If you build a new plant, it clearly provides certainty of supply and certainty of capital costs, but clearly it raises uncertainties about regulatory recovery, but I would argue that that's sort of a different issue than we're addressing today.

If you acquire an existing plant -- one of the questions for today -- clearly, again, you're achieving certainty of supply and capital cost, but you're also adding the potential to acquire that plant at a discount to the cost of new-build, so you're doing something good for customers, but, again, I said before, you also have the uncertainties around regulatory recovery.

I'd now like to move to the third option, contract for power capacity. Yes, you do achieve certainty of cost and supply as in the other two alternatives, but you are also subject to counterparty credit risk, and that's a really big deal that the financial markets are focusing on.

Should I contract for a long-term agreement with someone if they may not be there in the future, and once they are no longer there because they have gone bankrupt, will I still have that supply that I have contracted for?

And I think lawyers will tell me -- I'm not a lawyer -- that that's probably not the case and you won't have access to that.

The second issue -- and this is a really big deal -- credit quality issue regarding PPAs relate an imputed debt which creates an adverse financial impact to utilities, so the rating agencies are saying that if you enter into power purchase contracts, we're going to impute the obligation associated with that contract as debt on your balance sheet.

So, why would someone think about entering into a PPA in that sort of environment? It's taking on debt, it's increasing the cost of capital. There is no near-term benefit associated with it.

And finally, I'd like to talk to the fact that clearly we talked about certainty of cost and supply, but typically you don't enter into a purchase power contract for the life of the asset, so the certainty that you have is for probably a shorter period than the life of the asset itself.

Let me move on to the merchant generator's perspective. For those in financial distress, as I see it, the alternatives to optimize the value of their assets include the following:

They can clearly enter into PPAs, but as I just said, they are not likely to have the credit capacity to create stability over the term of any meaningful contract, so it's going to be hard for them to enter into long-term PPAs, because the party on the other side has the load-serving obligation and is going to be reticent to enter into that PPA with a weak, financially distressed counterparty.

Number two, they can sell their assets. But the investor pool today is quite shallow to recover investment in generation assets, and it will be further depressed if we don't allow utility purchasers to get into the market, so we'd be reducing the competitive pool for buyers for power assets.

As it relates to merchant generators and thinking about the future for building merchant power plants, that won't be able to be done with a significant level of debt under the current paradigm that we live in, and, therefore, we're going to have to rethink about how power plants will be built in the future.

From an investor perspective -- and I'm really speaking from a financial investor perspective -- during 1998 to 2002, power plants were built and financed with too much debt relative to cashflow associated with those assets.

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Significant capital was invested in merchant power plants today, and today that capital is badly impaired and investors have been adversely impacted. Precluding utilities from purchase of power plants, merchant power plants, will reduce the value of such assets and adversely impact investor ability recover their investments.

In the future, investors will not fund merchant power plants without clear transparency as to the viability of the future profits from that endeavor. In additional, substantial equity will be required, and thus that will clearly raise the price for power.

Finally, existing merchant plant investors are impaired by the lack of ability to sell to utilities and that will clearly reduce the value of their assets and their ability to recover their investment.

Let me sort of digress and now move on to the status of the environment to sell merchant power plants today. The market, as I said before, is very shallow.

We have hedge funds and other financial investors who are willing to consider acquisition of assets at a large discount to replacement cost to the objective clearly of seeking a premium return on equity. And I don't know what the calibration is, but let's just say it's 25 percent-plus.

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We have strategic investors who have checked out of the game due to their own financial concerns regarding credit and earnings implications, and the lack of clarity as to the specific timeframe for recovery of the industry.

The banks, Citigroup being one of them, are actively considering their alternatives for power assets under our control. Finally, no merchant power asset seller is currently being coerced to sell their assets to utilities.

In a free market, investors should be able to make clean and quick decisions to optimize the value of their portfolios. So I'd like to conclude:

How is competition enhanced if utilities cannot acquire merchant power plants? As I said before, utilities will be cautious about long-term PPAs, given a rating agency approach that will require equity to support imputed purchase power obligation debt.

If utilities are opposed to PPAs due to this related imputation and they are not allowed to purchase existing merchant assets, they will likely build new plants, as required to serve their load.

The building of such additional plant without effective deployment of surplus power generation capacity, will further impair the value of existing distressed power plants.

From financial investors' perspective, they clearly seek the flexibility to monetize the value of their investment, and by reducing the investor pool for such investments, asset values will be further impaired from already depressed levels, and if potential investors, being utilities, are precluded from the marketplace, the cost of capital will increase in that marketplace, so, thus, how can increasing the cost of capital enlarge competition or enhance capital availability?

From a merchant power strategic investor's perspective, creating a transparent market and regulatory structure, noting the complexities that exist on regional market differences, for power supply options, will enhance the potential for competitive markets, owners of competitive power assets, load suppliers, and customers.

Two, the market and regulatory structure should allow for load-serving entities to be indifferent as to their source of load, whether they build it, buy it, or contract for it.

How to create a such a market regulatory structure should really be left to those that have expertise in designing functioning competitive markets, but precluding utilities from the acquisition of merchant assets, without addressing market structures that are failing, is a paradox.

Asset owners and investors of currently depressed assets are having their ability to liquidate their investments, unfairly compromised. I'd like to end with an example.

I don't know if you might have noticed in the press a couple of weeks ago that Duke Energy announced that it was selling a number of its assets in the southeast United States. They were able to negotiate a price of $90 per kilowatt or $250 per baseload kilowatt, and they sold that to a bunch of -- well, to a hedge fund -- versus Entergy, which agreed to acquire the Perryville Asset from CLECO, or at least a portion thereof, which was able to realize $245 per kilowatt, or Arizona Public Service, which just announced its purchase from PPL for a peaking facility.

The others I was telling you about had some baseload component, but this was a peaking facility at $420 per kilowatt, so from an investor perspective, it seems to me that when you take utilities out of the mix, the value that's realized for the owners of those assets on the sale of those assets, is clearly depressed.

I thank the Commission for the opportunity to present my views this afternoon.

MS. SIMLER: Thank you very much. Are there any clarifying questions?

MR. PERLMAN: I have one very quick clarifying question, and, in view of the time, I will be brief and ask you to be brief, too.

We've been told that utilities, from an investor perspective, prefer purchasing assets to contracts, because they can earn a regulated return on the purchase, as opposed to a pass-through on the contracts. Is that something that you all consider when you look at this from an investor perspective?

MR. KIND: That wasn't the point that I was referring to earlier. I basically said the difference was that when you build the asset and own it, it's on your balance sheet. Yes, you earn a return on it, but you have equity behind it.

When you purchase through a contract, the agencies are saying, you've added risk to the equation. Now, where's your equity to reflect the increased risk?

And if I can't earn a return on that equity, I'm diluting the value of my credit quality, and I'm also diluting the value of my equity security and I'm increasing the cost of the capital going forward, whether that's to fund a power plant, whether that's to fund a hookup to someone's home.

MR. PERLMAN: Thank you.

MR. TIGER: As a further point of clarification, when S&P looks at that, for instance, doesn't it depend ultimately on the riskiness of the PPA that they are entering into, that the utility is entering into?

And given the nature of whether it's a take-or-pay or if it's another type, that it makes a difference, so they are a little more nuanced than just describing full debt treatment?

MR. KIND: Yes, that's correct; there are some shades of gray.

MR. TIGER: I guess -- I'll follow up later.

MS. SIMLER: Mr. Delaney with Oklahoma Gas and Electric.

MR. DELANEY: Thank you. I'm the Chief Operating Officer of OGE Energy Corporation and its subsidiary, Oklahoma Gas and Electric, an integrated electric utility. Prior to OGE, I spent more than 15 years in investment banking for the firms of Kidder, Peabody; Bear Stearns, and UBS Warburg, representing and advising utilities, IPPs and other energy companies.

OGE, currently, as you know, is seeking permission under Section 2.03 to acquire a portion of an existing generation facility in Oklahoma, and my remarks today are designed not to address any specific issues that are pending before the Commission.

I appreciate the opportunity to speak on these important competitive issues. Today, I will highlight the major points of my statement, but later add my complete statement to the record.

OGE has long supported the Commission's pro-competition goals. OGE led efforts, though unsuccessful, to deregulate the electric retail markets in Oklahoma.

OGE was and remains a principal supporter of the creation of the RTO in the Southwest Power Pool. OGE sells power primarily to retail customers in Oklahoma and Arkansas, and neither state has approved retail access.

As a result, OG&E must stand ready under state law to serve in a reliable manner, its retail customers, as well as any other increase in load within OG&E's service territory. And that's an important distinction from other markets where utilities sell their generation and new wholesale markets were established.

In our state, like many other states, there is no re-aggregation issue, since there never was a disaggregation.

My comments today focus on three important points: First, that limiting the utilities' resource options in meetings its retail load obligations, will invariably increase retail customers' electric rates.

Secondly, that utilities buying IPP plants, will not, per se, harm the competitiveness of the wholesale markets, and, in fact, may help competition in the long run, and, thirdly, that existing FERC policies regarding Section 203 applications, in conjunction with state oversight of resource planning adequately protects wholesale competition, while still allowing public utilities to acquire merchant generation facilities.

As to my first point on higher retail price, a public utility may fulfill its duty to serve by constructing new generation, by purchasing capacity on the open market, or by purchasing an existing generation unit.

Resource options are evaluated based on delivery over the longer term, the lowest cost supply to our customers on a risk-adjusted and most reliable basis. And in a region where supply exceeds demand, the utility should be able to purchase capacity, either through a PPA, or by acquiring an existing plant at a price significantly below the cost to build a new plant.

Based on our experience, IPPs price their capacity for a given term, relative to their view of the forward curve for capacity. Indeed, our experience has been that there is a very steep price curve when it comes to contracts of ten years, much less 30 years, such that a price of even a ten-year PPA exceeds the cost to our retail customers of buying a plant where the price is fixed for over 30 years.

Thus, we believe the Commission should not assume that long-term PPA are available as a viable alternative to purchasing a plant. In the case of an absolute obligation to serve, the utility, in my judgment, seeks to avoid future price uncertainty and credit risk by acquiring a unit which locks in low-cost power for the more than 30 years of the life of the plant.

The Commission should be aware of all of the costs imposed by entering into a long-term PPA, as was just discussed. Rating agencies view long-term PPAs as debt equivalents on a utility's balance sheet, and increase the utility's debt in determining ratings.

Consequently, the utility with a long-term PPA must either suffer a decrease in its buying capacity or offset a weakening credit ratio by higher return on equity, which adds cost to the PPA alterative.

In OG&E's market, we believe that if the IPP knew that utilities' only options are to build a unit or enter into a -- build a new plant or enter into a PPA, the IPP would price its power to the utility, just below the price it would otherwise cost to build a plant.

My second point is that utilities buying merchant power plants will not, per se, harm competition in the wholesale markets, and, in fact, may help competition on the long run. Recent history has shown that IPPs with plants in multiple markets, are selling plants in some markets to raise cash to strengthen its financial position, or reinvest in other markets where it has stronger competitive position.

Precluding utilities from acquiring a plant may likely mean the IPP will receive a lower price for the plant or, worse, have no buyer at all. However, the issue of helping or hurting IPPs should not be confused with the real issue in a Section 2.03 case, whether a utility buying a merchant power plant harms competition, and, if so, how to mitigate the harm resulting from the transaction.

Competition, has not, per se, increased, if a utility buys power through a long-term contract, rather than buying the plant itself. Whether a utility contracts for 100 megawatts for 30 years or buys 100 megawatts of the plant, the potential future supply for wholesale customers and the impact of either option are the same.

Under both options, the IPP will not be able to offer that capacity to other wholesale customers. Under either option, the utility has access to the wholesale market to meet the needs of its customers.

My third point is that the Commission's current policies and practices for evaluating purchases of generating assets are adequate and are not in need of major change. The Commission should not lose sight of the fact that its precedent correctly holds that FERC should protect competition, not competitors or certain segments of the market.

Under the Commission's existing policies, a Commissioner evaluates potential market power issues using competitive analysis screens and determines what, if any, mitigation measures are appropriate to offset any potential increase in market power resulting from the proposed transaction.

Any wholesale customer perceives itself harmed by the transaction may actively participate in the FERC proceeding. In addition, prudencey oversight in numerous states by state regulators, including Oklahoma, provides adequate protection for retail customers.

I do not see the shortcoming in this process. FERC may adopted tailored mitigation processes that are a true nexus to the effects of the transaction. Further, has we have discussed previously, no two markets are the same, and for this reason, it is highly likely that no two transactions will have the same effects or warrant the same type of mitigation.

Finally, with regard to the Commission's request for comments on economic dispatch, it has been asserted that requiring utilities to purchase from them will mean cheaper power for consumers. That is a worthy debate, but this is the real issue in a Section 2.03 case, does economic dispatch plan truly have a nexus to the effect of a proposed transaction?

It's difficult to see, for example, how a transaction which a utility proposes to buy a single generating unit cannot be mitigated unless the utility also includes all third-party generation in the market in its dispatch.

To the extent an IPP believes that it can offer less expensive energy to the utility than produced by its own units, then the IPP should raise that issue at the state commission in an appropriate proceeding.

OGE urges the Commission to continue to continue to respect the state commissions' ability to act on these issues. The IPPs have also asserted that economic dispatch is necessary because the utilities control transmission.

While the IPP has a legitimate complaint about transmission access, it may also file a complaint with the Commission under Order No. 888. IPPs have asserted that economic dispatch is necessary to address the utilities' monopsony power, another way to access retail customers in states without retail access, but such an argument, we believe, is misplaced.

A monopsonist uses its position as a buyer to lower the prices of its suppliers by artificially lowering demand. It is difficult to see how a utility with an obligation to serve, can artificially lower demand to affect the seller's prices.

In sum, the Commission should recognize that limiting a utility's resource options in meetings its retail load obligations will invariably increase the retail customer's electric rates, and utilities buying IPP plants will not, per se, harm the competitiveness of the wholesale markets and may actually help competition in the long run.

The Commission, we think, should not lose sight of the real issue in the Section 2.03 case, whether the proposed transaction harms competition and, if so, what tailored measures with a nexus to the harm will mitigate the harm?

Existing FERC policies with regard to Section 2.03 applications, in conjunction with state prudencey oversight of resource planning, adequately protect wholesale competition while still allowing public utilities to acquire merchant generating facilities.

Again, many thanks to the Commission for permitting me to provide OG&E's views on these important matters.

MS. SIMLER: Thank you. Any clarifying questions?

(No response.)

MS. SIMLER: Next we have Mr. Steve Daniel with GDS Associates, here on behalf of the Cooperative Interests.

MR. DANIEL: Good afternoon. Thank you. Commissioners and Staff, I'm a power supply planning consultant with GDS Associates, and I'm here today representing a group of transmission-dependent utilities -- Arkansas Electric Cooperative, Alabama Electric Cooperative, KEPCO, Kansas Electric Power Cooperative, Golden Spread Electric Cooperative, Seminole Electric Cooperative, and Old Dominion.

These TDU systems are generation and transmission systems whose members serve approximately 2.5 million customers throughout eight states, generally in the southeast.

We have provided written comments, and I'll try to briefly summarize some of the key points. As has long been the case, these TDUs support truly competitive markets -- and I emphasize, "truly" -- they support regional transmission access under Commission-approved RTOs, and policies that facilitate these two objectives.

We do appreciate the opportunity to be here again and to participate in these venues that FERC has convened to address critical policy issues.

I was asked to present for this group today, primarily because of our firm's experiences in actually managing power solicitation requests for TDUS, some of these TDUs and other load-serving entities.

In the last several years, we've managed between 25 and 30 RFPs. This has included solicitations for thousands of megawatts of capacity and we think we understand the realities of the marketplace, and I must point out that most of this experience has been in regions that lacked RTOs.

Some of the key observations that we've gleaned in this process and through this experience are the following: The existence of real competition often is illusory. Load-serving entities desire often, types of power that others are not willing to provide, other than the control area operator.

Examples of those are requirements power and load-following type services. Severe transmission limitations exist in certain region and that limits access to alternative supplies.

Of 20 RFPs we've done in the past three years, half involve significant transmission limitations with regard to deliverability. We find that there are willing bidders, but we have serious and constraining deliverability issues with regard to transmission.

I'll give you a couple of examples: Kepco in Kansas was seeking to move nine megawatts from the Westar area into Empire District Electric Company and was faced with an estimated network upgrade fee of $30 million to move nine megawatts.

If the Cooperative had paid that upgrade fee to get that nine megawatts, of course -- it would have been prohibited to do so -- that would have cost them significantly, but added significantly to the transfer capability of the grid, at no cost to other potential users and solely at Kepco's expense.

Another example is Kepco seeking to move 140 megawatts in order to serve a portion of its load in the

Westar area. And in that situation, we had wiling bidders, but we had multiple transmission limitations that kept some of those alterative bidders from being viable.

So these are some of the things that we've faced in this process. Some of the things that we've concluded from being in the market for the past four or five years under the current conditions, are the following:

Access to low-cost alternative resources are often severely hampered by transmission limitations. In our view, generation dominance within load pocket control areas is real and continues to exist today.

We think that policies that favor local generation in the context that I have just presented to you, is at odds with the development of truly competitive markets.

Now, how does this relate to today's technical conference? Acquisition of distressed independent merchant generation by already market-dominant regulated systems will lead to further concentration and decreased competitiveness, we believe.

Transfer to regulated utilities of their affiliated merchant generation will take more capacity out of the wholesale markets. Such acquisitions are often consummated before public disclosure, which means that systems like my clients, generally are not able to participate.

Also, the smaller systems such as the ones that we represent, are unable to compete against the large IOUs in such acquisitions, for both technical and financial reasons -- technical meaning that they can't necessarily always absorb large chunks of generation such as what you would have in a 700 megawatt resource, and, of course, financial meaning that some of these resources that are available, if they were to try to buy all of them, they would not be able to do that, financially.

How can the Commission help establish policies to keep from adversely affecting competitive markets and further exacerbating this situation? There are several examples:

We think participant funding tends to force load-serving entities to favor the local generation within a control area, which is predominantly owned by the incumbent transmission owner IOUs.

We think that not counting all capacity owned by these incumbents in market power screens, ignores the use of those resources by those investor-owned utilities in formulating market-based sale types of arrangements, an example being that it's not uncommon in the bid process to get a proposal where you will have a non-rate-based, unit-specific capacity pricing arrangement, but there will be a system-firm energy type arrangement backing it, which means that regulated assets are being used to backstand those non-regulated sales. Some of the solutions that we see to deal with these situations in the marketplace today are as follows: We think that the Commission should consider denying market-based rate authority to any generation-dominant public utility that is not a participant in a Commission-approved RTO.

We think the Commission should consider all generation capacity owned by a public utility when applying market power screens to determine qualification for market-based rate authority.

To avoid the application of participant funding to network customers or the funding of in-region network transmission upgrades needed to accommodate network transmission resources would help to overcome the effects of being forced to favor local generation within a control area.

We also encourage the Commission to consider requiring unit participation by smaller load-serving entities in merchant generation acquired by public utilities as a means of mitigating their market power dominance. We thank you again for the opportunity to be here and we look forward to any questions that you have of us.

MS. SIMLER: Thank you.

MR. HUNGER: I've got a clarifying question. Steve, when you say that the Commission should consider all capacity controlled by the utility, when you say that in the context of both analyzing under a Section 2.03 and a market-based rates applications, are you saying that the Commission shouldn't deduct -- make some sort of deduction for capacity committed to native load; is that what that meant?

MR. DANIEL: Yes.

MR. HUNGER: Okay, thanks.

MS. SIMLER: Mr. Hilke, with the FTC.

MR. HILKE: As the morning, my remarks are prefaced by the disclaimer that my comments reflect my personal views and do not purport to be the views of the Federal Trade Commission or any individual Commissioner.

In my comments on utility solicitation processes this morning, I emphasized two points: First, that transactions between regulated utilities and their respective unregulated affiliates, may harm consumers if these transactions allow suppliers to exercise more of their market power by evading rate regulation, while they allow the regulated parent to cross-subsidize inefficient, unregulated affiliate operations.

The bottom line: Discrimination by utilities may harm consumers by enhancing market power or expanding relatively inefficient suppliers.

The second point I made is that discrimination in the solicitation processes potentially creates long-term inefficiencies in wholesale markets, above and beyond the immediate pricing effects, because they create incorrect investment incentives for customers.

These same concerns apply to asset transfers between the utility and its unregulated affiliates, although the mechanism and effects of the discrimination differ to some degree. Essentially, the framework for analysis is similar and the techniques for establishing market values in order to detect and prevent asset transfers that occur at non-market levels, use the same technique.

These techniques, as I mentioned this morning for detecting this type of behavior, including setting up a formal bidding model, doing comparative transactions in similar markets, extending cost-based rate approaches to affiliate transactions, ex post prudencey reviews and reliance on third-part analysts to compare bids in determining the winning bid.

The range of techniques for avoiding cross-subsidization is also similar for asset transfers and supply transactions. These techniques include establishing market prices for transactions between utilities and various forms of unbundling or separation of utilities from their affiliates on a line-of-business by line-of-business basis.

Accounting separation of all these various forms of separation is the least likely to be effective. Hence, one of the potential harms from acquisitions of affiliate assets is that such transactions move the markets from moderately effective forms of separation, namely, a combination of operational and accounting separation, to one in which there is only accounting separation preventing the discrimination.

Where unbundling through operational separation has been found to have benefits, the reverse, that is, rebundling, is likely to result in a loss of some of the same benefits that were realized by the original unbundling, ergo, they should be treated in a parallel fashion in terms of the analysis that is conducted.

What I would like to highlight this afternoon is that discrimination in asset acquisitions by utilities may very well contribute to an increase in market power in wholesale markets and retail electricity markets by increasing concentration and creating new entry barriers.

Hence, the affiliate abuse prong of the four-part test that we talked about yesterday, and the creation of barriers to entry prong, may be closely related, and I would like to describe that briefly.

Both concentration on the supply side and entry barriers are permanent factors in assessing the state of competition in wholesale markets. When the mechanism for increased concentration is that discrimination favoring affiliates and asset acquisition will focus exit in the electricity markets on those assets owned by independent generators, hence the focus of the exit, if there is excess capacity, will be on the independent generators, leaving more and more in the hands of the existing incumbent firms.

Rather than exit being focused on the least efficient units, as it would be in the absence of such discrimination, less efficient assets may be retained if they are affiliate assets, and more efficient assets may actually exit from the markets if they are independent assets.

The mechanism for increased barriers to entry is the increase in the proportion of total costs of entry that are likely to be unrecoverable. In antitrust analysis, one of the primary ways in which we analyze the level of barriers to entry is to look at these unrecoverable costs.

Absent discrimination, a generation entrant can reasonably expect to sell its generation assets at a fair market value, in the event that its entry fails. In the presence of discrimination in asset acquisitions by utilities, the selling price for liquidated, stand-alone generation assets may be lower than it would otherwise be, because there will be fewer potential buyers, or the buyers will only be willing to pay prices which are far below what they would pay under a normal market condition without the discrimination.

Because of the lower transmission costs and risk associated with local generation, the whole combination may result in this problem of unrecoverable costs and, therefore, reluctance on the part of potential entrants to enter into these markets to begin with.

I note that from the perspective of a utility, that discrimination in asset transfers may be doubly attractive, since it potentially both evades rate regulation, allowing the firm to exercise more of its market power, and increases or preserves future market power by causing exit of stand-alone generation rivals and by creating barriers to entry against new stand-alone generators, even if they are more efficient, absent the discrimination.

In conclusion, discrimination in transactions with affiliates of any type can create potentially substantial inefficiencies in both wholesale and retail electricity markets. Because wholesale and retail electricity markets are so closely related in the electricity industry, and because of technical characteristics of electricity, discrimination in retail markets can affect the wholesale market and vice versa.

There are some available techniques for establishing market values, which we talked about yesterday and was mentioned again today, the use of independent parties to evaluate these transactions is one of the most attractive of those.

Nevertheless, these techniques all present various challenges and are likely to be less effective than structural approaches that reduce or remove the incentives for discrimination in asset transfers and solicitation processes.

I'd like to add one final note: This is to comment briefly on the jurisdictional overlap between FERC and the antitrust agencies. While the antitrust agencies will review mergers of independent generators with utilities, asset transfers may very well be outside of what the antitrust agencies consider to be actionable transactions.

So, if FERC is not reviewing these transactions, either because of a policy decision or because of legislation, there may be no federal overview of asset transactions between affiliates and parents. Thank you.

MS. SIMLER: Thank you. I want to open this up to Q&A, and we're going to start wit the Staff and the participants at the table.

MR. PERLMAN: I have a question. Based on something that Mr. Delaney said, I wonder if anyone else has a reaction to it. If I heard you correctly, Mr. Delaney, you said that it's very often more cost effective to buy an asset than to enter into a contract, because the contract, sort of on the NPV value, would be much more expensive than buying the asset.

Why would anybody sell their asset for something that, on an NPV basis, is worth less than the revenue stream you would get over time? Is there some competitive issue going on here, or is that just the way people do business?

MR. DELANEY: Our experience has been that a lot of the sales and decisions have been because of either the financial need or the fact that strategically -- as we know, we've talked about that we have a patchwork of different market structures, and a lot of the wholesale participants have different portfolios, and in some markets, they have a stronger position, a stronger portfolio of assets.

I think that in the market we are in, where we don't have retail access and nobody has a real portfolio, we see that there's sometimes a strategic decision to take capital out of our market and invest in markets where it's perceived to be better supply/demand balance, better potential framework, better opportunities.

We look at the buying of power plants effectively locking in for 30 years, so the comparable analysis is an economic analysis of looking at a 30-year PPA. And what we're seeing is that if you're a company and you make a strategic decision to get out of a market, that's one reason, but if you're sitting there and you've got an investment and you're trying to decide, where is the market going to be in 30 years and you think there may be a potential runup, you know, a very significant runup as we have had in the past, in ten years out, you're not going to be really willing to lock that in at a lower price for 30 years.

And that is what my point is, that at this point, our experience has been that we can buy, through buying a power plant and locking in prices for 30 years, cheaper than we can through a PPA.

MR. PERLMAN: Can anyone else address that?

MR. ESPOSITO: Thank you. I guess I'd have to ask the question, why would anybody want to lock anything in in this day and age of technology and productivity advancement, for 30 years? I mean, ten or 12 years ago, the state-of-the-art technology for heat rates may have been 10,000 or 12,000. Now it's 7,000, so to buy a gas plant, even a 7,000 gas plant today, you may be seeing half of that in terms of heat rates, five to ten years from now, or, conversely, as we're seeing right now, you may see the gas price be three times that.

I was just doing a little bit of math and hearing a lot about the costs of using a PPA, and, you know, we talked about an undefined increase in borrowing costs because of what it does to your balance sheet and other things that S&P and Moody's and those types look at, but what about the defined cost today?

It's easy to calculate, $6 gas, 7,000 heat rate; that's $42 a megawatt. Bump that up to a 14,000 heat rate, that's $84 a megawatt, easy math, easy to figure out. It's there today; it's quantifiable.

When utilities run these old plants, as they do today, instead of running the IPP plants and buying the IPP power short-term, consumers are paying that $42, so, you know, that can repeat itself again. You had the cost of nuclear plants go up, we had a whole big round of stranded costs. Why do we want to get into that?

I'd like to, if I could take a moment, and just respond to the proposition that IPPs need utilities to be buying their plants from them. I mean, why aren't the IPPs here saying, we want that? None of them are saying that, so you've got to look at that, and what they're asking for is an open market.

I think that in an open market where you can actually sell your power, where you can give the consumer some of this benefit of the $42 delta, and take some of that benefit to your own bottom line or debt service or wherever you have to take it to, you know, they are going to want to see the market and to be able to sell the power, and the plant values will come up.

You will have better plant values, and as Mr. Hilke said, more realistic plant values, so you won't have strange aberrations down the road. Thank you.

MS. SIMLER: Mr. Kind?

MR. KIND: Yes, I would just add to that that, first of all, I'm not speaking on behalf of the Citibank, portfolio managers that some would suggest are going to own about 19,000 megawatts of generation over the next couple of years, but IPPs aren't the only players that own power plants.

And that speaks to the question, David, that you asked earlier, which was, you know, why does someone sell at a price that may look to be below its NPV value, because what is the NPV value that each party is looking at?

They're not looking at the same set of metrics, and the IPP or whoever, the distressed owner of the power plant, has to look at what his alternatives are, what his cost of capital is, and he may not be in charge of his own destiny. He may have a bankruptcy coming up upon him, so he's got to deal with liquidity. It's not just about NPVs. You've got to deal with what we learned about in the last five years, and that is that liquidity is not something that is just a given.

It maybe was for the power industry prior to -- for the first 15 to 17 year of my career, liquidity wasn't an issue. Come 2001, we learned that liquidity is a major issue, so that's why someone may sell, even though the price doesn't look attractive.

And I thought that the comment that Mr. Delaney made -- and I apologize -- Ms. Wong from CERA made -- was sort of the same comment I made, which was that, you know, the rating agencies are just adding a new cost. We could define that cost. We haven't defined that today, but clearly it is something that scares potential buyers or contracting parties from moving forward.

MR. OGUR: I have a clarifying question for John Hilke, and I may have simply missed the point that you were making. You were talking about a process in which less efficient affiliate assets were retained in the industry, and more efficient independent assets were exiting, which was the opposite of what you would expect in an efficient market.

I thought you were relating that to an asset transfer from the independents to regulated utilities, and that's where I lost the connection, so if you could clarify that.

MR. HILKE: The point was that an affiliate can go bankrupt without the parent going bankrupt.

MR. OGUR: Right.

MR. HILKE: Whereas if the parent goes acquires the affiliate and it rolls it into the rate base, there's little, you know, risk of going under. So that way, potentially, the inefficient affiliate ends up being retained because it's now rolled into the rate base, and if somebody has to exit because there is excess capacity in the market, the remaining candidates to exit are the more efficient, stand-alone plants.

MR. OGUR: Okay, I see, thanks.

MR. TIGER: For Mr. Delaney, I had a question. You mentioned that there may be economic incentives and it may make more economic sense for ratepayers ultimately to purchase rather than enter into a PPA, given forward curves.

The question that that might raise is, should one do an economic analysis of the impact on ratepayers, in other words, look at all the viable alternatives. When we're looking at filing here, should we be doing some type of Edgar standard that looks at the economics of ultimate ratepayer, as opposed to just the competitive impacts?

MR. DELANEY: I think that in my comments I said that when we go through that process, in which we do look at the economic impact, and when we make such a step or make such an acquisition, we look at the alternatives, that when we make a filing on that from the retail ratepayer, we will, in fact, have a prudencey hearing, in our case, at the Oklahoma Corporation Commission, and they will look at it, as well as all of the intervenors that we have in those proceedings will evaluate and see what evaluation and what process we went through to make sure that we made an economic decision for our retail ratepayers.

And I think that we feel that that's what the states do a good job of that, and that's where that responsibility should rest.

MR. ESPOSITO: We would clearly encourage the Commission, both at the state and the federal level, to look at those kinds of analyses. I mean, you all have jurisdiction over the wholesale sale aspect of these kinds of transactions.

I would also hasten to mention that in many states, there are limits on just how far the public service commissions can go in really reviewing these things. I believe that in Oklahoma, there is case law to the effect of limiting the OCC's jurisdiction to look into things that somebody might characterize as micro-managing the utility.

And we are particularly fearful that what's going to happen here is that this case will come from the FERC over to the OCC, and OG&E will say, well, wait a minute, you guys don't have authority to look at this here under your statute, and, particularly IRPs and an economic dispatch kind of approach.

I'd love to hear Mr. Delaney say here that OG&E would not go to court to stop the OCC and encourage a full examination of those issues.

MR. DELANEY: I think the rules were that we were not going to discuss the specifics of that case, and so I'll honor the Commission's request and not respond to that.

I would like to say, however, on the heat rate discussion that went back to some math and 7,000 versus 14,000, I would point out that our heat -- they are very efficient combined-cycle facilities out there at 7,000 heat rate. That's a variable cost only, and as we know, those assets need fixed O&M, they need capital costs to survive.

And so I think to take the seven versus 14 is a little bit misleading to determine what the potential savings is, because there is another cost component that goes in there.

MR. ESPOSITO: I'd agree that there's a wide range there, but I would also agree that we're not talking about a 22-percent return on equity, after tax, for 30 years. I mean, people who run IPPs realize that they are at risk and they are not always going to get a huge return.

MR. PERLMAN: But the issue that I think this conversation illustrates, at least to me, is that I agree with what Mr. Delaney and Mr. Kind said, and that was, in a lot of ways, these people are having to make a strategic decision.

They have a good asset. They have a combined-cycle that looks the same, whether it's in New England or in Oklahoma or whatever. It's the same thing. It's burning gas, it has the same heat rate, and they have a liquidity crunch. They've got to pay their debt service, whatever, and they are making a decision where they can make money and they're choosing to go into markets that are more liquid and competitive and causing potential concentration furtherance in the areas where there's less competition, and that's the issue that we have to grapple with here when we look at that.

And everybody's got a good story, because they've got the liquidity problem; the utility has a legitimate need, and instead of moving towards a more competitive market, which is why they went there in the first place, we're moving away from a more competitive market, potentially, and that's what we're really trying to deal with, and it seems problematic for us, because, you know, again, everybody's got a good story.

But the overall big picture program is hurt, potentially by this, and that's why the Commission is looking at it. Is that wrong way to look at this issue?

MR. DELANEY: Well, again, I guess the assumption is that by removing that asset, it's going to hurt the competitiveness of that market, and there's a lot of -- as we know and as all of us know, there's a lot of ingredient that go into a market and what makes it competitive, instead of just isolating on one part of that.

MR. KIND: I think we're also adding a new set of rules to the game, that if the capital providers were aware of the rules that we're possibly going to be creating, that didn't exist at the time, the question is, would that capital have been provided to fund that plant at that point in time?

I don't know the answer because I'm Monday-morning quarterbacking, but we're clearly changing the rules, and, you know, as Citibank, as we go through our credit analysis, would clearly have to reflect that as we think about future opportunities.

MR. O'NEILL: What did you think the credit rules were? What did you think the assumptions were, going into this?

MR. KIND: By the way, I apologize, Mr. O'Neill, that I'm not on the credit side. As I said, I wasn't speaking for our credit guys, but I think it's fair to say that people goofed.

MR. O'NEILL: Yeah, but you say that the rug has been pulled out. You said that -- what were the assumptions? You don't know what the assumptions were?

MR. KIND: Repeat the question. I'm sorry.

MR. O'NEILL: What were the assumptions going into this process?

MR. KIND: Prior to financing a given power plant?

MR. O'NEILL: When they were financing IPPs?

MR. KIND: Yeah, I think there was an assumption -- first of all, there was a competitive market for capital, and investors were very hungry to throw capital at deals that seemed viable. There were and are credit people and consultants that were providing us analysis that would suggest that there was sufficient demand to soak up that capacity, and that there was transmission access that was available.

And when you combine all of these factors, whether it be -- you know, I don't want to blame any particular party, because I think all the parties to the process probably deserve blame, but investors put up capital based upon some assumptions that never played out.

And now the question is, how do those investors optimize their investment?

MR. O'NEILL: So you never worried about the idea that the vertically-integrated utility would build their own plants and compete away the virtue of IPPs?

MR. KIND: Mr. O'Neill, as I said, I'm not a part of that process, so I can't -- but I doubt that was really the view. We knew that there was a hybrid market that existed, but obviously we were only lending to a project if we felt that project, by itself, was viable.

But the fundamental assumptions that underlay those analyses were clearly flawed, in hindsight.

MR. O'NEILL: But at the time, did you believe that those investments were competitively viable in the market?

MR. KIND: Obviously, or we wouldn't have made them otherwise.

MR. O'NEILL: Do you still believe that, if they had the transmission access, and if they had the --

MR. KIND: As I said, I'm not going to speak for our IRM Department, our workout guys.

MR. O'NEILL: Speak for yourself.

MR. KIND: I don't believe these are viable investments in the current market environment over the next couple of years.

MR. O'NEILL: I'm saying, if all of your assumptions came true, would they have won competitively over the rate-based generation?

MR. KIND: I don't know the answer to that. I'd have to do the analysis later on.

MR. DANIEL: In the next five to ten years, probably not, because I think people lost sight of the fact that there's got to be some reasonable balance between supply and demand, and there as a significant overbuilding of capacity under some great expectations that there was a lot of money to be made.

And, therefore, once you passed a reasonable threshold of capacity relative to load, then those investments, in my mind, began to become very questionable as to whether they could hold up at the prices levels at the investment costs that were being made.

And what you saw was, you saw capacity go up in price, where combined-cycle units that could be built for $500 early in this process, ended up being built for $600, $700, and $800 a kilowatt, so that the rush resulted in inflated costs of these units.

At some point, there was a real question as to whether they were going to be viable.

MS. SIMLER: Excuse me, we're running out of time, and I just wanted to hit on one question that Dr. Hilke teed up, and it was part of our agenda, and I want to pose it to Mr. Daniel.

It has to do with an Edgar type solicitation that Sebastian mentioned, and you, as a wholesale customer, quite possibly without the protection of a state regulatory agency, I wanted to hear if such a competitive solicitation process on an Edgar-type standard with you on the 2.03 side, when you're acquiring a plant, would be a benefit?

MR. DANIEL: You're talking about when a public utility regulated by the Commission is buying a plant?

MS. SIMLER: No, if the coop were to go out and look to acquire a plant and if this Commission, you know, as a general matter, in all of its 2.03 acquisition reviews, had a competitive solicitation and an Edgar-type review standard in place for 2.03 reviews, would that be of benefit to the types of clients you represent, as a market approach?

MR. DANIEL: Well, what I'm struggling with is that most of my clients have pretty stringent solicitation requirements under their lender requirements. RUS is a big part of that process, so they already have to go through solicitations and do that sort of thing.

So, I'm not sure whether the Commission would want to come in and overlay on top of them, another process that would apply to the cooperatives in that regard.

But as far as the market power side, I can't visualize -- and I have to be real careful, because we've got some clients that have filings before the Commission right now that are regulated, but from a market power perspective, most of these systems wouldn't have market power, so I'm not sure of the need for investigations of that type.

MR. PERLMAN: How about and flip it around like you were saying. I think Jamie makes a good point. The retail customers in Oklahoma have the OCC, but I would suspect that the wholesale customers -- I know that to the degree that they are requirements customers or something like that, the FERC is the regulatory body of jurisdiction, so with -- would your customers benefit if the FERC were to require such a thing, to the degree that there were any acquisitions that would affect their wholesale rates?

MR. DANIEL: Again, I'm not sure that would be of particular benefit to them. These are member-owned systems, and they are governed by their members, and, therefore, that's a pretty good control to begin with in terms of the decisionmaking that they do.

And then they also have to follow the solicitation processes and the RUS and the oversight, and their acquisitions are scrutinized heavily as part of receiving financing.

MS. SIMLER: Thank you. We'll take a short break of ten minutes, and we'll be back to start with the second panel. Thanks.

(Recess.)

MS. SIMLER: Can we start Panel No. 2?

(Pause.)

All right, we're going to start with our second panel. I want to thank them all for joining us and participating, and we're going to start on the right again with Christine Tezak of Schwab.

MS. TEZAK: Thank you. I will briefly go through the points I wanted to highlight in response to the questions that were put before us, and thank you all for having me back.

First, I was frustrated by the wisdom of providing a trend analysis on asset transfers, given that nothing in the last 15 years has been driven by what I would consider to be market forces or economic trends, but instead, by political fashions careening towards restructured markets and then away from them with equal speed, so I could not provide anything that I felt was particularly valuable or insightful.

Regarding the question as to whether or not merger principles already address the competitive effects of integrated utilities and IPP assets, I do think that the merger principals that are in place, already do address the analysis of deltas and market concentration that are precipitated by the change in owernship of assets.

One of the things that I stumbled on when looking at trying to define competitive effects between an acquisition of an asset and a long-term contract, is that I was having trouble delineating what, exactly, is the difference in actual competitive result, given that the same number of megawatts is technically removed from the market, the same level of demand is removed from the market, whether it's an acquisition or a contract with a long-term -- is a longer term with a specific asset owner.

And so the ownership of the asset became less clear to me, if the actual result was merely the fact that some demand was going to be satisfied through a specific transaction for a finite period of time and would no longer be participating on an active, competitive basis.

So I stumbled upon that because I had trouble finding for you, a distinction in competitive effect.

One of the things, while I was thinking about this, is that the competitive effects of vertically-integrated utilities and how they are acquiring and operating generation in today's marketplace.

One of the things that I think we need to realize when we look at the impact of competition, is the kind of structures we are creating. It is interesting to me that a generation-owning, transmission-operating, that is, a utility that's not in an RTO, reminds me a lot of the advantages touted in Enron's One Too Many trading model.

Sure, others can participate, but Enron or the marketmaker would ultimately be the most successful, or at least that's what they would pitch to Wall Street, since they would leverage the wealth of information, in fact, near perfect information that would be provided to it by others, including its customers, in order to facilitate its making its own market best.

Does that mean that customers would not benefit relative to the prior choices, if their relative transaction costs declined in that model? Well, no, but it does provide the opportunity for the marketmaker to use that information in a near-monopoly fashion to control a submarket.

And this was astonishing to me as I thought about strange this is that we're really calling it. It is a very similar model as far as managing whether it's trading information in volumes and megawatts or whether it's access to transmission, how seductive the idea of near perfect information is to investors and why something that verges on monopoly on that fashion, is often regulated.

It is also interesting to me, however, given the shaking of confidence that has happened in this industry since the decline of Enron, that the industry is no longer endorsing this model, and it's many to many with an impartial broker like the Intercontinental Exchange and NYMEX, that is inspiring more confidence and seems to be leading the direction forward.

The question that was also put before us is -- one of the most significant things that I feel is shaping the long- and short-term markets is not the transfer of assets, but what customers are actually available to compete for it.

The wholesale market has shrunk dramatically. The commercial industrial market is difficult. Now, the long-spurned, load-serving entity load, retail load, is now courted, and, in fact, in some markets, it's the only game in town.

This is what I think is shaping competition in long- and short-term markets, not who owns which assets. Assets that were built to serve wholesale opportunities, and could serve them with energy-only service, may, in fact, be poorly positioned to compete effectively for capacity-driven LSE load. If it's poorly positioned for even wholesale markets, well, then it's twice disadvantaged.

The high returns we saw a few years ago, were supposed to offset the troughs, and, in fact, were argued for, given the fact that we had regulatory risk. The fact that many of us, including myself, may have treated that regulatory risk and the possibility that restructured markets could face difficulties so casually, is part of the risk/reward proposition that we accepted many years ago.

As far as safety net, I can give you a long and detailed analysis on this, which some of you have seen, but, further, I have been unsuccessful in finding any real evidence of it. In fact, when I attended an event that was hosted by Standard and Poor's Utility Ratings Group in New York last week, it is not whether or not an asset belongs to an affiliate that makes a difference in its credit quality, but often whether or not it was ever part of rate base, whether or not it has network resource status, and not whether or not it's an affiliate.

It is actually how that asset is connected to the grid and under what terms that is the ultimate arbiter of valuation.

One of the other problems that clearly we're struggling with is that there is no one single number to represent the magnitude of difference between the value of energy and the value of a network resource status.

What we do know, however, is the cost of new construction is often greater than the book value of an existing network resource, or the value of a generation plant with a contract. Those are, in turn, more valuable than uncommitted energy-only capacity in today's markets.

I do believe transactions need to be reviewed for affiliate abuse. Whether it requires an Edgar type standard, is difficult for me to say.

Clearly there were issues and shortcomings with applying that model, as it is, to transactions such as Ameren, when we look at an asset transfer market that has far less liquidity than existing markets for contracts.

Should competitive solicitations be one way to address these issues? I certainly would think that it could be a way to meet a standard under a test for affiliate abuse, but I am concerned about the concept that we could see a mandate from the FERC, requiring one.

In some markets, if what we are looking at is competition for retail load and if the procurement by a load-serving entity is reviewed by the state, I am not sure how those two things will mesh without conflict. Frankly, we have plenty of that already.

The lobbying, I think, to change the stance of how transactions should be evaluated, may need to take place more at the state level when it comes to making procurement decisions, than here at FERC, because I think now what we're struggling with in this marketplace is what does make a transaction prudent and competitive, particularly for native load?

If the bar is merely the avoided cost of construction, then, arguably, any existing asset that is networked is going to meet that test.

Perhaps what needs to be considered, not only here at the FERC, but also by state commissions that review prudent procurement, is whether or not, in fact, a particular transaction is the best the market has to offer. Thank you.

MS. SIMLER: Thanks. Any clarifying questions?

(No response.)

MS. SIMLER: Okay, Marji Philips with PSEG.

MS. PHILIPS: Thank you. David Perlman, earlier, pretty much summed up my speech, but I'm going to torture you all and make you listen to five more minutes of it.

Thank you for giving us the opportunity to express the PSEG Companies' concerns about the recent trends involving utility purchases of affiliate merchant plants. Let me briefly describe what the PSEG Companies do, so you will understand where our concerns are coming from.

We're a group of diversified companies that include PSEG Power, my company, which is engaged in the merchant generation and trading business, and Public Service Electric and Gas Company is my affiliate, which is a franchised transmission distribution utility operating in New Jersey.

PSEG Power, through our subsidiaries, owns about 14,000 megawatts of generation. We've built two state-of-the-art combined-cycle plants in the Midwest, with the megawatts of approximately 1900 megawatts. We've acquired two fossil fuel units in New England, with a total capacity of 970 megawatts.

We purchased a plant in New York, and we're replacing it with a significantly more environmentally friendly unit that's about 763 megawatts, and our remaining portfolio is located in PJM.

Our business plan has been to commit most of the output of these facilities under long-term contracts, reached either through negotiated bilateral contracts with load-serving entities, or through contracts awarded through competitive wholesale procurement programs for ultimate supply to retail load, such as the New Jersey BGS auction, which you have heard about.

And I have in and make a statement to something that was said this morning, that they though the amount of load put out to auction in New Jersey was relatively small. By my standards, 10,000 to 12,000 megawatts is not a small amount of load to be put out to auction.

We have a good operational history, a record of regulatory compliance, strong credit, and have consistently demonstrated a strong commitment to the environment. We are the kind of company that has remained and will remain among the solid performers who continue to make investments to further your goal of a competitive market.

I'm here to tell you about what we perceive to be the negative impact on our business, created by utility purchases of affiliate merchant generation or what we call reverse unbundling. To be honest, I'm surprised there's even a need to discuss this matter, because such transactions are so obviously detrimental in so many ways to wholesale competition.

That's why it was very baffling to us when in evaluating the competitive impacts of such transactions on the wholesale market, FERC Staff rejected the concept that the ability to place distressed assets into rate base, provides a safety net that harms wholesale competition.

Staff said that this kind of behavior has to happen on a widespread basis before it impacts competition. In New England, you have previously acknowledged in many Orders that moving merchant plants back into rate base, even temporarily through reliability must-run contracts, is both detrimental to the markets and unduly burdensome on the ratepayer.

Here, as we would suggest, there is just the opposite of what Staff concluded in another case, that the transfer of affiliate merchant generation to a utility, is an insidious practice, the cumulative effects of which manifest themselves over time. Each such transfer is another nail in the coffin of competitive wholesale markets.

I'm afraid the hammer has passed from Pacificorp to you guys. Let me cut to the chase. This is the impact of each of the transactions:

In an overbuilt market within which generation competes for small amounts of firm load opportunities, it removes an amount of load from that market that now will be served by the generation transferred into rate base, without being tested and exposed to competitive alternatives.

It also takes one more generator from the competitive market. This erosion from competitive markets and the Commission's acceptance, sends a message to the industry that the merchant model, which was never given a chance to fully function, is prematurely dead; that the Commission is now retreating from a quarter-century policy vision that was shared by Congress, to create robust competitive markets and to encourage construction of more efficient and environmentally friendly generating units, and sends the message that re-regulation is not only acceptable, but preferable.

The rest of the merchant generation in the region, who had bought into FERC's vision of competitive markets, and who do not have the opportunities to seek refuge from the bust in rate base, are left to compete for fewer and fewer scraps -- the load -- with no protection from high fuel prices and the overbuild.

Frankly, the Commission risks losing the commitment to competition that organizations such as my Company made through investments, precisely because we believed that the elimination of the regulatory hedge put all market participants on equal footing.

Certainly, it seems like the Commission has abandoned us. And what's truly mind-boggling to me is that what's being done here is that stranded costs are being returned to rate base and the guardians of ratepayer interests -- I mean the state commissions and consumer advocates -- in many cases, seem not to grasp the unintended consequences, or maybe they do, and they don't care.

The Commission Staff is mistaken if it believes the Commission will be able to have a second bite at the apple, if and when such utilities want to sell their formerly-merchant rate-based power into the wholesale market -- I'm sorry; they're merchant power, now rate-based into the wholesale market.

Such a utility manages its units on a portfolio basis, and will find ways to optimize the value of such rate-based generation, regardless of where it covenants to place its power. And we all know that these same companies do not want the fact that they're taking load out of the market and putting their generation back into rate base, to be considered when determining whether they have market power.

Moreover, it's a fallacy to assume that a utility that performs economic dispatch for its units, will do so on an equal footing for independent merchant plants. We have experience that contradicts this.

As we testified in the AEP expansion case, we had great difficulty in selling our test power, even below marginal costs of coal units in the region when we needed to run those plants for testing. Moreover, IPPs bidding into such a dispatch, may need to capture some of their capital costs in the energy bids, which is not true for the utility's generation, because the ratepayers are guaranteeing recovery of these costs.

We also know how we can play with rate base, and those utilities can also sneak some O&M cost out of the variable rate and put them into the rate base as well.

From a financial perspective, merchant generators cannot compete against entities that have what amounts to an unlimited bank loan, which is what the retail ratepayers are providing. The IPP units must meet loan covenants and operational performance criteria which the affiliate merchant plants no longer have to do.

Unfortunately, some of this is being driven by credit ratings, rather than a policy vision. The credit rating agencies indirectly advocate utilities rate-base their merchant generation by rewarding such utilities with good credit ratings.

By getting such favorable ratings, the utilities are then at an advantage in the capital markets. It's unfortunate that the credit rating agencies, whose primary purpose is to identify risk, appear to be driving public policy.

This is very short-sighted and an overreaction to the past couple of years in a business that is historically very cyclical with periods of boom and bust. The credit rating agency actions may result in a self-fulfilling prophecy of putting the competitive genie back in the bottle.

Let me conclude by saying that we acknowledge that in the short run, these transactions may make great sense for the utilities' bondholders and shareholders who engage in these transactions. The formerly-merchant units were built by utilities who, although they had projected forecasts of load growth in the next couple of years, nevertheless expected a boom period, and thus decided to invest in merchant generation in their own backyard, not utility self-billed.

This decision was intended to allow shareholders to reap the rewards of such investments, without an obligation to share any of these rewards with the utilities' ratepayers. Now that we're in a bust period, these shareholders are sharing the downside of this market with their ratepayers by flipping these assets back into rate base.

This a long-term loser for shareholders and consumer alike, because it undermines the benefit of competition that creates competitive prices, investment growth, and environmental efficiencies, and it undermines reliability.

We have an obligation to our shareholders, too, but we believe we enhance shareholder value and not compromise it by allowing the competitive markets to function without regulatory safety nets. If we're not afforded the opportunity to play in a truly competitive market, we're likely to shift our investment strategy away from serving wholesale load through our generation investments. Thank you.

MS. SIMLER: Thanks, Marji. Next we have Diana Moss with the American Antitrust Institute.

MS. MOSS: I'd like to thank the Commission for inviting me here today to share the American Antitrust Institute's views on Section 2.05 analysis and competitive issues.

For those of you who don't know AAI, we're a Washington, D.C. based nonprofit research and advocacy organization with a mission to increased the role of competition, assure that competition works in the interests of consumers, and to challenge abuses of concentrated economic power.

Much of what I'll say today looks to the regulatory and antitrust experience with 70 some odd mergers and acquisitions from the mid-1990s to 2002, primarily as a source of insight into how the Commission should be currently identifying and analyzing and remedying competitive issues raised by current transactions.

I think it's imperative that competitive applications be appropriately identified and analyzed and any problems remedied to ensure that competition and consumers are not harmed.

Just by way of preface, I would note that the number of 2.03 filings, just based on data taken off the

FERC website, has increased fourfold between 2002 and 2003, and more than twofold between 2003 and 2004, so the pace of activity is brisk.

Moreover, the potential magnitude for re-integration in the industry is rather high, and this is best illustrated by way of example. Even if a dominant utility in a small, transmission-constrained market were to acquire a merchant generator with a five-percent market share, the increase in market concentration that would stem from that would be significant.

To put numbers on this -- and concentration statistics are something that most can appreciate -- if the dominant firm has a market share of 60 percent and four remaining firms have shares of 20 percent, five, five, and five percent, concentration before the merger would be very high, over 5,000 and would produce an increase in concentration as a result of a dominant firm acquiring a small generator, well in excess of the threshold specified under the DOJ and FTC guidelines.

With all of this in mind, I'd like to discuss two issues: Today, identifying and remedying competitive issues that are raised by these transactions, and standards for competitive analysis.

Obviously, acquisition of merchant generation by a public utility or transfers from an unregulated affiliate to a regulated affiliate, raise both horizontal and vertical competitive issues. As you know, horizontal issues involve one level of production, mostly generation, and in this industry, while vertical issues involve more than one level of production, such as transmission inputs, delivered gas inputs -- if you're talking about gas-electric mergers -- generation inputs, in many of the current situations, and a downstream or an output market, which is typically the wholesale electricity market.

The Commission gets a lot of credit for accurately identifying some vertical concerns in recent cases such as chilling of incentives for entry resulting from noncompetitive input procurement. But there are other theories of competitive harm that the Commission should be looking for, including discrimination, raising rival's costs, input foreclosure, customer or generation foreclosure, anticompetitive information-sharing and regulatory evasion.

These are all vertical problems, competitive problems. Many of these issues dominated the transactions of the '90s, including the AEP-CSW, Ohio Edison-Centerior mergers, the Koch-Entergy joint venture, the Pacificorp-Peabody co-merger, never consummated, the Consumers Energy-Panhandle merger, the Pacific-Inova merger, and the list goes on and on.

By the way, a lot of this is discussed in a forthcoming paper on vertical integration that we'll be posting on our website within a couple of weeks.

It's important to accurately frame out the competitive issues in current transactions. Vertical combinations change incentives and ability to lessen competition through exclusionary conduct. Here, market competitiveness in terms of the level of concentration, not changes in concentration, are important to look at in upstream and downstream markets.

Obviously, transfers of generation don't combine competitors, or at one level of production or at different levels of production, but they nonetheless raise vertical issues that are very similar to what you would see in a merger context. Here, I'd encourage the Commission to evaluate the possibility of generation foreclosure, whereby rival generators can be foreclosed from access to utility buyers, as a result of an un-level procurement process.

I would also note the importance of identifying regulatory evasion problems whereby firms may have an incentive to artificially inflate prices of generation inputs, pass them on to regulated consumers, and shift profits from the regulated to the unregulated affiliate.

A look back again at the merger experience indicates a broad array of remedies that have targeted ability and incentive in a vertical context. Remedies include generation divestiture in Pacific-Inova, prohibitions on anticompetitive information-sharing, and also in Pacific-Inova, and transparent input procurement processes in Koch-Entergy.

The Commission standards of conduct in transmission and interconnection standards are very positive developments in reducing the potential for competitive problems. But when additional remedies are necessary, AAI would encourage the Commission to consider structural remedies, as opposed to behavioral fixes for addressing problems, including transmission expansion, divestiture, relinquishment of control over transmission, remedies that improve structural market competitiveness, that reduce concentration and ease of entry, are likely to be much more effective than ongoing conduct-based remedies that require compliance and Commission oversight.

When the Commission is limited in its ability to impose structural reforms, AAI encourages cooperative efforts with states, which may be in a better position to impose certain structural remedies in their review process.

We would also encourage the Commission not to rely overly on the assumption that retail regulation will always police and detect and constrain the evasion of retail regulation, particularly when wholesale and retail markets are so intertwined.

This is particularly important as states and utilities are pressured to address reliability issues and obtain supplies quickly to meet demand requirements. We'd also encourage the Commission to objectively evaluate claims that transactions enhance reliability as a defense for potentially anticompetitive effects.

The guidelines, the DOJ-FTC guidelines provide a balanced approach for weighing efficiency, legitimate efficiency gains against anticompetitive effects, but taking this out of context and putting more weight on reliability, as envisioned by the Blackout Report's reliability impact requirement and merger review, risks approval of transactions that could harm competition and consumers.

Finally, I'd like to say that we strongly support the Commission's application of a guidelines-like approach to its assessment of M&A activity under Section 2.03, but as I mentioned yesterday, we encourage the Commission to adopt a more uniform guidelines-type approach to evaluating all competitive issues under Sections 2.05 and 2.03, as opposed to the many varied screens and tests that are currently in place.

We'd also encourage the Commission, within the parameters of a guidelines-approach, to consider alternative approaches and procedures for assessing the likely competitive effects of transactions.

I say this after assessing the consistency of applicant-filed analyses for certain market across a number of Midwestern merger cases. This is also described in our upcoming report.

For example, a merger filing made in late 1999, estimated concentration in the Dayton Power and Light peak period market to be about 1300 HHI, while yet another merger filing made not a year and a half later, estimated concentration in the same market to be almost 6,000 HHI.

Likewise, a merger filing made in late 1997, estimated concentration in the Virginia Power market to be almost 7,000 HHI, while a filing made two years later, estimated concentration to be only about 2,000 HHI.

These inconsistencies in analysis provided in FERC merger filings, are likely accounted for, among other things, by expanding data sources, different approaches to calculating and allocating transmission availability, but a lot of the inconsistency stems from the use of different models by merger applicants.

One way for the Commission to improve consistency is to develop or adopt some form of standardized model that could be used as a check on what merger applicants provide, or merger applicants and non-merger applicants's transfers of capacity, or in the alternative, be used by the

Commission with applicant-provided information.

Even better, given the apparent downside of using some structural models, i.e. concentration statistics for electricity markets, AAI encourages the Commission to consider the use of simulation models, which may be better suited for evaluating competitive issues in electricity markets.

This will improve the consistency, predictability, and credibility of Commission analysis. Thanks again for the opportunity to offer comments, and I look forward to any questions.

MS. SIMLER: Thanks, Diana. Mr. Mark Cooper with the Consumer Federation of America.

MR. COOPER: Thank you. I thank the Commission for having me here today. For almost two decades, I have cautioned policymakers to move slowly when deregulating electricity because of its unique characteristics -- very small elasticities of supply and demand render market forces weak. Those are the things we mean by market forces.

The demanding physical nature of the commodity, the capital intensity of various sunk costs, mean that it's an inflexible system that doesn't generally have a lot of redundant capacity.

Vertical integration, which facilitates management of the network, frustrates market formation and operation.

As a result, market power can be exercised at much lower levels of concentration than is typical of most industries. The numbers that Diana mentioned to you -- all of them -- are far too high for the electric utility industry.

You need to take the merger guidelines very seriously. One thousand is the number, folks, and it was a good number then and it's a better number for electricity.

You may even have to use 500, because the elasticities of supply and demand are so low that market power is rampant.

It's a particularly cruel irony for me to appear today at a proceeding to discuss the extent to which we should allow dominant firms to reconcentrate their local markets by buying up the pieces of the collapsing deregulation experiment.

Having failed to protect consumers from the abuse of market power in the past by failing to de-monopolize before we deregulated, now we're wondering about how to quickly re-monopolize without a mechanism to actually protect consumers in the future.

I hate to be "I told you so," but I did. And it has cost consumers tens of billions of dollars.

In January 200, we urged the Commission to reconsider its Order 2000, warning that the analysis of market structure leads to the conclusion that market power can be exercised in these markets because they are thin.

Now, prior to 2000, we vigorously supported divestiture of generation assets, and then after we saw the 1998 price spikes, looked at what was happening, we changed. We started telling regulators not to lose control of their strategic assets.

In essence, we said don't flip them out, and now we're trying to flip them back in. As frequently is the case, the consumer is getting the short end of the stick on both transactions.

In March of 2001, we offered Ten Commandments for Restructuring. Unfortunately, this proceeding has at its heart, the violation of six of those Ten Commandments: Focus on structure, not behavior, well, maybe we'll get a structural rule here; do not deregulate the market until after open, adequate highways of commerce are in place, and we certainly do not have those; do not deregulate until there is an effectively competitive generation market with adequate supplies, well, in a few places, we have and in a few places, we don't, most places, we don't; require reserve margins to lower the risk that consumers will be forced into volatile spot markets; do serious law enforcement, and this Agency has not; establish real responsibility.

In November of 2002, after the fiasco of the Western markets, we asked the FERC to demand much more of electricity markets before they considered relying on market-based rates, reminding FERC that it is a widely accepted principle of economic practice that structural remedies are vastly superior to conduct or behavioral remedies.

Under the severe conditions that obtain in electricity markets, it is clear that both are needed, but the fundamental principle is more important. No amount of market design, which is essentially a behavioral approach, can compensate for a lack of actual competition.

Earlier this week, we intervened in the PJM interconnection proceeding, again, appalled at FERC's unwillingness to discipline market power. The PJM Order deals with the pricing of generation in circumstances where it is acknowledged that competitive forces are insufficient to discipline price.

One would have thought that the rule was focused on preventing the exercise of generation market power and thus protecting consumers, but review of the PJM Order showed us that this assumption is incorrect.

In simple terms, the path on which the Federal Energy Regulatory Commission is proceeding, cannot possibly lead to a competitive, consumer-friendly industry. This proceeding to consider re-concentration of electricity markets is perhaps the pinnacle of the irony of electricity restructuring.

In short, the FERC needs to restructure restructuring. It needs to focus on generation markets, narrow the role of spot markets, narrow -- eliminate the role of spot markets in transmission. Frankly, it hasn't generated an increase in investment there. There's been utter failure on both sides to create capacity and also to create fairness.

The FERC needs to support the implementation of the Public Utility Holding Company Act; the FERC needs to honor the contracts that protect native load, not the ones that protect market traders who benefitted brutally from manipulated markets.

I think we can say this is the worst of all possible words, but the industry continually invents new ways, new scenarios that look worse than the ones before. And this is a perfect example: Re-concentration of markets that were inadequately de-monopolized, without consumer protections, truly will produce the worst of both possible worlds.

We suffered when they flipped them out, and we'll suffer when they flip them back in. Thank you.

MS. SIMLER: Thank you, Mr. Cooper. Dr. DeRamus.

MR. DeRAMUS: Thank you very much. My comments today will be largely focused on vertical market power, including monopsony or buyer market power and its consequences for assessing the competitive impact of the acquisition and disposition of merchant generation assets by public utilities.

I addressed similar issues in yesterday's technical conference on market-based rates. Given the substantial overlap in the issues raised in both conferences, in order to avoid undue repetition of the comments I gave yesterday, I have made those comments available to this technical conference for those who are interested. They are attached to my comments that I distributed earlier.

While my remarks in this conference are not being sponsored by an market participant, I should also note that I am currently testifying on behalf of Intergen in OG&E's proposed McClain acquisition, which is also captioned in today's conference.

In the late 1990s, merchant generation was seen as the primary source of growth and efficiency in restructured markets. Since that time period, merchant generation has suffered a remarkable reversal of fortunes, experiencing not only severe financial difficulties, but also a significant change in policy and regulatory attitudes towards the sector.

As a consequence, the last two years have witnessed a substantial increase in utility acquisitions of distressed merchant assets and the absorption of some utility affiliates back into the regulated rate base, a process that has sometimes been called vertical re-integration.

I should also note that I consider many other forms of interaffiliate transactions, such as preferential access to a regulated affiliate's financing capacity, or preferential interaffiliate PPAs to be part and parcel of these broader market developments affecting the merchant generation sector.

This process of vertical re-integration has often been accompanied, in my view, by a less than satisfactory regulatory review of the long-term consequences of these transactions for the development of competitive markets.

As a result, there has often been insufficient, ineffective, or nonexistent mitigation to address the potential for competitive harm. Thus, particularly at this point in time, I think there is a pressing need for the Commission to more clearly articulate the specific market power issues that should be addressed, prior to approving such transactions, and to impose mitigation measures that actually resolve those fundamental market power issues.

I fully recognize that there can be good arguments in favor of vertical integration in specific instances, both with regard to efficiency, coordination, and even investment incentives, regardless of when the vertical integration comes about over the course of the business cycle.

I also fully recognize that competitive markets will produce winners and losers, and that the financial distress of a market participant is not, in and of itself, necessarily a cause for policy concern. In fact, an acquisition may be one means of keeping the productive assets of a distressed company in the market as a supply alternative.

Such considerations, however, do not mean that one can ignore an acquisition's potential for competitive harm and the exercise of market power.

As I discussed yesterday, market power comes in two flavors: Horizontal and vertical. Horizontal market power is typically exercised by reducing output, while vertical market power is typically exercised through various forms of market foreclosure.

The market power issues raised by these distressed asset acquisitions that have been insufficiently addressed by regulators, relate primarily to vertical market foreclosure. In particular, I am concerned with the following three questions:

First, how much of the asset distress is due to market foreclosure by the utility itself?

Second, can the particular acquisition, regardless of whether it is distressed, enhance the utility's ability to foreclose the market to its remaining competitors?

Third, can any of the claimed benefits o the merger be achieved through pro-competitive alternatives?

A simple initial indicator of the potential market foreclosure may be the efficiency of the distressed asset itself. At the margin, if there is excess capacity in a workably competitive market, I would expect the least efficient unit to be the one most in danger of exiting the market, not the most efficient unit.

As an aside, I should note that we heard some other arguments raised with respect to interaffiliate transactions. Similarly, a transaction should not fundamentally change the extent to which a distressed asset is dispatching.

If dispatching an asset is economic after the acquisition, I would expect that such a dispatch should have been economic before the acquisition, as well.

Unfortunately, I think there may be some institutional resistance to addressing broader questions of market foreclosure when a transaction involves the acquisition by a utility of generation assets. Since such transactions are generally considered horizontal mergers, the focus is typically on horizontal market power, except to the extent that specific transmission issues arise.

Broader considerations of vertical market foreclosure, by contrast, are typically confined to typical vertical mergers, such as when an electric utility buys a gas pipeline or a coal mine.

It is my contention, however, that issues of broader vertical market foreclosure can apply equally, if not more so, to utility acquisitions of distressed generation.

There are two primary vertical market power issues that such an acquisition can raise: First, the acquisition of additional generation by a vertically-integrated utility, particularly a utility outside of an RTO, may increase the utility's ability to use its control over transmission in order to foreclose competitors from the wholesale market.

Since a utility can strategically affect the transmission available to competing generators through its own dispatch decisions, the increase in its dispatch choices that accompany an acquisition, also have the potential to increase its transmission-related market power.

The AEP-CSW merger raised such issues, and, in fact, a market monitor was put in place in order to identify such behavior after the merger.

I should note that, as a general matter, I am not particularly confident of a market monitor's ability to identify or remedy vertical market foreclosure, and I have a strong preference for more structural mitigation as one observes in Order 2000.

Second, a distressed acquisition may reflect a vertically-integrated utility's refusal to purchase from a lower-cost competing generator, effectively forcing the competitor from the market, and buying its assets at a bargain price.

Further, the acquisition may increase the utility's ability and incentive to engage in such vertical market foreclosure with respect to the remaining competitors in the market, since it increases the size of a utility's rate base and supplies the utility with a greater amount of its own generation to substitute for the generation of its remaining competitors.

The fact that a utility's incentives to engage in vertical market foreclosure derives in some measure from cost-of-service regulation, does not by any means suggest that I question a given state's authority to retain such cost-of-service regulation.

I simply think it is important to understand the incentives of market participants, in order to identify whether a transaction is likely to result in anticompetitive consequences in order to fashion appropriate mitigation.

I also think that it is important at this stage of the analysis to clearly recognize that this form of vertical market foreclosure through a refusal to purchase, involves the exercise of buyer market power.

A utility with a native load obligation can exercise buyer market power, only because it also has its own generation that it can substitute for its competitors' generation, even if its own generation is more costly.

This buyer market power rises to the level of monopsony power -- the equivalent of monopoly -- when a utility comprises such a substantial share of load in the relevant market, that it impedes the ability of competing generators to sell in that market.

Given the confusion that the word, "monopsony" seems capable of sewing, it is perhaps worth clarifying a few things about monopsony. Monopsony power is not the Wal-Mart Happy Face, bouncing gleefully from product to product, magically knocking their prices down in some consumer nirvana.

Monopsony power does not involve reducing input prices to a more competitive level, but, rather reducing input prices below their competitive level.

Furthermore, the monopsonist does so with the intent to increase its own profits above a competitive level, not to see the smile on the consumer's shining face by reducing the price at which it sells its final product.

In addition, while I will not bore you with the details, standard models of monopsony also show that monopsony power over inputs, when combined with the monopoly power in the output market, leads to prices and profits in the final product market that are even higher than the prices and profits that would obtain under monopoly alone.

Let us all be very clear on this most fundamental of points: The exercise of monopsony power is anticompetitive.

I presume that is why monopsony power is mentioned in the Commission's merger policy statement, and this is also why I do not consider it to be a new market power issue, whether for merger analysis or for granting market-based rate authority.

My primary concern in raising monopsony in this conference, however, is not that a monopsonist utility will end up paying competing generators, a less than competitive price for their power by reducing its demand.

Rather, my concern is that a monopsonist utility will refuse to buy any power from competing generators, in order to, in effect, maintain its generation monopoly with respect its own native load and monopolize the market for generation in the remainder of the wholesale market.

It has long been recognized that efforts to monopolize can be fueled by monopsony power, just as efforts to monopolize one market can be fueled by monopoly power in related input markets such as transmission or gas.

Some individuals may prefer to call this monopoly leveraging, since the utility is leveraging its monopoly over retail service. I would prefer to call it monopsony leveraging, since the relevant market power driving the foreclosure is ultimately buyer market power.

It may also be possible to consider this to be a form of inappropriate affiliate preference or almost an intra-affiliate preference, or an evasion of rate regulation.

But whatever you want to call it for analytical or even procedural purposes, the end result is still the same: The foreclosure of low-cost competing generators from the wholesale market.

What the Commission's current merger review standards allow for the analysis of vertical market power issues, including monopsony power, I do think the Commission should provide greater clarity on the above issues.

In addition, while the Commission has stated that historical trade data can be useful for merger analysis, I think it is important that the Commission place greater emphasis on such data in merger proceedings, as well as in market-based rate proceedings.

Yesterday, Commission Staff asked how to identify vertical market power -- I'm sorry, how to identify vertical market foreclosure. Current merger reviews focus primarily on capacity shares, not actual observed market shares, and one way to identify vertical market foreclosure may be to examine whether there is a major discrepancy between the two.

Similarly, if a vertically-integrated utility consistently dispatches its own, higher-cost generation in the presence of lower-cost competing alternatives, this also may indicate some form of vertical market foreclosure.

One can also compare a utility's actual capacity factors with those predicted by the competitive analysis screen, or one can compare its actual versus predicted frequency of dispatch. I have found such comparisons to be particularly illuminating in analyzing vertical market power.

Finally, I also think it is important that the Commission consider whether mitigation truly address the underlying vertical market power issues and vertical market foreclosure in a substantive way.

In particular, the type of vertical market foreclosure discussed above, driven by a utility's refusal to purchase from lower-cost competing alternatives, is simply not susceptible to being remedied by an after-the-fact monitoring of the utility's behavior.

By contrast, I think the implementation of structural solutions, such as a competitive procurement process, i.e., including at least some amount of independent generation in a utility's economic dispatch protocol, can be an important means with which to mitigate vertical market power concerns raised by a specific transaction, as well as similar concerns that arise in market-based rate proceedings.

Properly structured, a competitive procurement process would result in the dispatch of the most efficient generation available, regardless of ownership, providing transparency to a utility's dispatch decisions.

Such a competitive procurement process would also provide clear efficiency benefit to ratepayers, prevent their foreclosure of low-cost competitives from the market, and impose no compulsion on a vertically-integrated utility to purchase from the competing generator, in the event that the utility is able to provide generation at a lower cost than its competitors. Thank you.

MR. HUNGER: I guess I'll start with Diana, and I think I'll ask a similar question to David.

Diana, you talked about the problems associated with regulatory evasion in the context of acquiring -- a utility acquiring an affiliated plant.

And you noted that regulatory evasion is usually considered a vertical problem. And David also noted that -- looked at acquiring generation in a vertical context, as well as in a horizontal context.

And in the case you brought up, Diana, would -- since the concern is, in that case, of paying too much for the affiliated plant and passing it on, would using an Edgar standard for affiliated generation acquisitions get at that problem? Would that enable the Commission to better analyze that type of problem?

MS. MOSS: You know, in thinking about this, just hearing these conversations in the last two days, you know, I think it's important to distinguish between -- well, just really to distinguish between four things:

If it's a power purchase, then you're talking about the prices at which generation is being purchased at, potentially inflated, and then passed on to consumers.

If you're talking about an asset transfer, then you're concerned more about the purchase price of the asset being potentially inflated and passed on to consumers under the rate base.

It's almost a timing issue. Does the inflation occur in the process of purchasing inputs on an ongoing contractual basis, or does it occur at sort of terms of a one-shot deal in terms of transferring the asset and rolling it into the rate base?

I think both potentially pose evasion problems. I'm not sure, but I think the Edgar standards will get at -- application of the Edgar standards to transfers will get at the one-shot deal problem where you have an asset transfer, but I'm not sure that they will get at sort of the ongoing monitoring of or prevention of inflated input prices being passed on and cost allocation systems being potentially distorted and passed on to the regulated ratepayers.

So you can call it a timing problem, you can call it a regulation, jurisdictional regulation problem. Is FERC going to handle the asset transfers? Are we going to rely on the states to handle ongoing monitoring of the interaffiliate transactions?

I think markets are so intertwined, wholesale and retail markets are so intertwined that FERC's got be involved in the evasion issue, and I think, as John Hilke mentioned earlier, the antitrust agencies may not have a whole lot to say or do in this particular instance.

But I guess my thought is, to answer your question directly is, the Edgar standards are certainly a good start, but I'm not sure that they will capture the entire -- all the possibilities for passing on inflated costs.

MR. DeRAMUS: Maybe it might be helpful for me to kind of direct my comments at more the general principle that I think that's involved.

As I understand it, the Edgar standards are what I would think would be the appropriate standard to apply in an interaffiliate transaction, is, you are trying to determine what is a true competitive benchmark price for the transfer of an asset.

I think the best way to elicit that information is to actually go out and have a competitive solicitation. For many years, I have done transfer pricing, and I know you go to comparables, when you don't have an intra-affiliate transaction, you go to comparables to try to figure out what is reasonable for some compliance purposes, in that case, tax compliance.

And that has some merit in that kind of context, but in the particular case of analyzing the potential for competitive consequences, and particularly for the potential for vertical market foreclosure, I think you have to have that kind of competitive procurement process.

If you are really in a jurisdiction where there just aren't any -- there's nobody else bidding, that opens up a whole other can of worms, but when you have people, other independents out there who are willing to show you what the price is, I think you should let the market work.

MR. COOPER: Let me try that. It's interesting. In thinking back, I made the point that we changed sides in the circumstance here in the late '90s.

One of the reasons we did was that in our view -- and when we start looking at this question of introducing competition into generation markets, which we vigorously supported in the late '80s and early '90s, our view was, in fact, the competitive acquisition model, subject to the structure of utility regulation, et cetera.

The idea was to take this one piece of it out, and we looked at all of those competitive bids and there were problems with them, but for every megawatt that was put out for bid, people offered ten megawatts to build, and that looked like a place where consumers could actually have a better market standard.

Of course, in the late '90s, we got into something different, which was the spot market for all electrons that looked like a very different beast. But the interesting question here is that the notion you have now of competitive acquisition for an asset being let on the market, or the equivalent of an asset, makes sense to us.

This is the framework within which you can manage this kind of market, inject competition into it -- that's the original idea we had in mind, and I defy you to go back to the debates of the passage of EPAC and find people talk about spot markets and electrons. They just simply did not.

Their model was competitive acquisition through essentially the offer of an asset or a bundle of electrons over the course of time and see who would offer to provide that at the lowest price. The same principle ought to apply here, that is, a real standard.

If there are no bidders, then you've got a problem, and so that is one way in which to introduce discipline back into the market.

The other standard is simple; that is, consumers always get, in my world, the highest price when we sell a asset and the lowest price when we buy it, so you could look around for an equivalent and say, well, then, you're not allowed to charge more than X. And if anyone is willing to supply those electrons for less than X, they win the bid.

MR. O'NEILL: Can I ask the panel what they think our chances are of getting the competitive result when affiliates are participating in these procurements?

MS. PHILIPS: I don't think you're going to have much success, frankly, in getting -- even the Edgar standard, it's a good place to start, but the competitive -- the harm to competition continues long after you've been able to prove the Edgar standard.

We've heard it in terms of manipulating transmission and available capacity in terms of dispatch. The only way you're going to get them, like everything else, is in the pocketbook, and you do have other remedies.

You have the ability to control market-based rates, you have the ability to play in other markets. You've all heard me rant that many of these noncompetitive players are very quick to buy from PJM when they're short and it's a hot time in the summer.

You make it harder; you put a tax on them. They don't want competition, then they have to pay a tax for competition. There are various other ways of getting at this.

I think you're right; it fundamentally starts at the retail level. It's kind of shocking, what's going on at the state level, and many of us are participating there, and in frustration, are now looking for some guidance from you, because it was Congress's and your vision to not go this way.

So you may not get it from the review standard, but you can get a reaction through other of your oversight authority.

MR. COOPER: I take the question to be, in a distressed market, why would any anybody bid on that asset?

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MR. O'NEILL: I mean --

MR. COOPER: And the answer is, you're probably right, and if nobody bids, then I don't think you should let a transaction take place, because there is no market.

MR. O'NEILL: But it was more to the point that if we have these competitive procurements and nine people show up, one of them is affiliates, and affiliates seem to win all the time, do we have -- is that -- how do we discipline that process?

MS. TEZAK: Well, first, you have to make an assumption that the process is, indeed, broken.

MR. O'NEILL: Yes.

MS. TEZAK: If you have a competitive bid, a competitive solicitation where the simple reality happens to be that the business model of the affiliate when it was founded, was to chase and serve the LSE load as a primary customer, okay, and they're interconnected in that way, and the other eight bidders that show up, happen to be underutilized capacity that was constructed to serve a wholesale and industrial market that has since gone West and happened to be connected as energy-only, would you explain to me what is broken about the ability of an affiliate that is network resourced available and constructed, always was constructed for that particular business model, to not prevail, if those are actually -- that's actually the evidence in the competition?

MR. O'NEILL: So is this --

MR. COOPER: But see, here, the interesting thing is that this one question -- and since I've known you, I know what your prejudices are -- what happens if no one is able to win because they can't count on transmission rights, for instance?

So you walk in and you say, if I buy that plant, is my assumption going to be able to -- am I going to be able to run it as much as he can assume, well, then, what you may have to do is put the parent at risk.

So, when you put that plant out for bid, you have to couple that with the rights to transmit the electricity, and if you lose the bid to someone else who has a different asset, you still have to sell the rights to transmit the electricity.

You can construct your market --

MR. O'NEILL: I think what Christine described is the example where the affiliate is the only who shows up who can get transmission access, so that maybe the nine other bids have to be thrown out and --

MR. COOPER: Or, in which case, they bid a higher price because they really don't think they can run as much, because they -- but the answer -- then you might have to put the transmission rights at risk. So, if a utility says I want to buy back an affiliate, then maybe you expose them to that risk.

In my world, this is a heinous act, and an affiliate buying back something they flipped out, is really very bothersome to me, and so that might be a legitimate way to expose them to risk, and introduce some discipline back into that bid process.

MS. TEZAK: But I have a way to help out the other eight bidders. And it's actually something I read in Staff testimony in a case here.

And that is, if you are looking at a situation where you do have a single bidder that looks like shew-in because of the parameters of the solicitation, then what we need to do is, if we honestly believe that there are opportunities for others to serve this load on a more competitive basis, but we have a transmission issue that needs to be resolved, then what we need to do is, if we're going to set standards for competitive bids, is to set them in such a way so that we resolve the problem.

How do we resolve the problem if we have a whole bunch of competitors that are existing with energy-only interconnection? There has to be enough time for those who elect to, to pick up the phone, call the TO and request a network resource study that would change their status.

There has to be enough time for the TO to execute that under the terms of the new interconnection standards, and only in that way will the people that are charged with evaluating the prudencey of this transaction, whether at the state level or at FERC, will have all the information that's necessary.

There's absolutely no reason to embark on a punitive regime in order to solve the problem. The problem is, can we open the door further by adding time?

MR. O'NEILL: So you think that the utility who is about to buy affiliate assets is going to do a bang-up job at the network study?

MS. TEZAK: If you're not enforcing that as a separate issue --

MR. O'NEILL: You would like the market discipline to enforce it.

MS. TEZAK: Well, you don't have market discipline if you're going to make energy-only resources on the same part as network-only resources. I mean, there's a reason why PJM beats generators who interconnect in PJM into network resource status from the get-go, because it solves a hell of a lot of problems later on.

MS. MOSS: Let me just state -- I guess, approach this from a slightly different perspective and a broader perspective. I think the points that I tried to make today and yesterday are that the Commission is really at a threshold here.

There are new, novel competitive issues being raised by these transactions. The Commission has never dealt with customer foreclosure, which is preventing competitors, rival generators in the market, from getting access to a buyer of their output, either their asset or their output.

The Commission is expert at dealing with transmission foreclosure, ala AEP-CSW and Ohio Edison-Centerior. You guys know that, you've done it, and it's a proven problem and there are remedies for it.

But evasion and customer foreclosure or generation foreclosure new, novel issues. My concern with just an application of the Edgar Standard as sort of a blanket fix for all this, sort of goes to my answer to David's question, but I think you have to take a really hard look at a) is that a structural or a behavioral remedy?

Well, to me, it seems like a lot of sort of ongoing monitoring and enforcement of meeting the standard. That takes time; it's costly from a regulatory perspective.

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There's always the possibility for gaming the system because it's conduct-based or behavioral. I think there's a real opportunity here to set the stage for a smoother transition that the industry is currently in, by looking at structural remedies.

You can apply an Edgar Standard or sort of transparency in the input procurement process, but you may want to get at it through sort of more permanent fixes like transmission expansion. If you can widen the scope of markets, if you can reduce incentive by divestiture or through -- somehow. I know it's difficult for the Commission to require divestiture, if not impossible.

But there are ways. If you can broaden the scope of markets and reduce concentration, a lot of these issues are not going to be competitive problems because the markets will be bigger and more competitive.

And I think there is a real opportunity here to maybe choose a different path, and that is to get at, instead of layering more behavioral or conduct-based remedies onto the system, which is pretty much all conduct-based as it is, with access, compulsory access and all of this stuff, I think there's an opportunity to really move in a different direction.

MR. O'NEILL: And you think that will solve the affiliate problem?

MS. MOSS: You know, that's a tough one. I don't think it's going to solve the affiliate problem, but it's certainly going to get at the underlying market structures that would otherwise make the affiliate problem a problem.

MR. PERLMAN: Are you saying that the way to do it is, rather than go through this behavioral stuff and Edgar, is to compel divestiture or compel significant transmission expansion? And how would we do that? I don't know what the ways are that you said that we have to do those things.

MS. MOSS: I don't think FERC has good ways. We dealt with this when I --

MR. PERLMAN: So if we don't have those ways, and we can't do what you're suggesting, what do we do?

MS. MOSS: In a couple of merger cases, at least one that I can recall, the Commission sort of tag-teamed with the states, because the states had issues with these, competitive issues with these transactions, and tag-team with the states and base conditional approvals on what states were able to implement, to remedy competitive concerns.

A lot of times states have the ability to deal with divestiture issues and transmission expansion, whereas it might be more difficult for the Commission to do it.

So, you know, I think it takes creative approaches, particularly for the magnitude, the potential magnitude and complexity of these vertical issues that we're dealing with.

MR. COOPER: Are you saying that you don't have the power to implement my Fourth Commandment? Essentially, that may be a problem, and I've said that before.

The transmission capacity is the highway, and you're suggesting you don't have adequate powers, but the answer may be, rather than try and do it at a general level, to do it in each specific case.

So, here's a merger conditioned upon the question of the transfer of those -- exposing those transmission rights to loss and risk in the competitive acquisition process, that, you probably can do as a step to mitigate the threat to market power.

The bigger problem, you may not be able to do, compel doubling the size of the highway.

MS. PHILIPS: Could I just jump in a bit, as a player in the industry? The real two issues you have heard are the monopsony power, which was eloquently stated down there, and the other is transmission, which I hate to say it, we have no -- you guys have no control of what goes on in the transmission room of an entity that still controls its facilities.

You've never been able, because we have been complaining to you for years about the reservation of network load. Every year, it grows. It usually, coincidentally, grows when someone puts in a request for a merchant plant. Usually then the generation disappears and, low and behold, it's for network growth.

We still don't have uniform ATC standards to figure out if everybody is really appropriately allocating transmission, so the truth is, until you force folks into an RTO, which we know didn't meet with a lot of happiness earlier, that that's the real structural fix here.

So what you could do, taking up on this, is, on a case-by-case basis, require what you did in the AEP merger, which is someone independent has to go in and oversee the transmission system, which is, you had PJM go in and do it for AEP.

And if they want to bring the merchant base back in, the merchant asset, you have to have confidence that they're not gaming the transmission system. And, by the way, when they're in there doing that, maybe they can oversee the dispatch, as well.

But until you actually get someone independent overseeing that stuff, you know, we're not going to really fix the problem.

MR. DeRAMUS: I might jump in, if we're still on the same question. Because, to some extent, I feel like I have brought some of these issues together and now I'm tempted to kind of pull them apart slightly, on the one hand, you have the interaffiliate transactions and on the other hand you have just a merger/acquisition that you're trying to evaluate.

And I think that, as I mentioned before, I thought there were similar issues in terms of the fact that you ultimately have intra-affiliate transactions that are -- they're quasi-transactions, but it's ultimately the decision by an incumbent utility to dispatch inefficient generation in the presence of low-cost alternatives, effectively meaning it's making an uneconomic choice and it's making that choice because it has no market discipline.

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Also, the common theme is that you need market discipline, both for those kinds of transactions, for daily dispatch decisions, as well as when you're talking about an asset sale, you need some kind of market price to figure out whether there is a problem.

Now, here is where I would probably want to separate the issues slightly, because if we just take some of the pure interaffiliate -- the pure affiliate transaction, where it doesn't involve -- it's not in the context of an acquisition, but just a previous merchant affiliate being brought back into the rate base, the problem is primarily one of regulatory -- it is that there are competitive concerns.

I think those competitive concerns are very serious, but in my mind, they are on the order of raising rivals' costs. They're not the kind of vertical market foreclosure that I look at and that I see when I see somebody refusing to purchase from a competitor.

So, given that the primary emphasis in those transaction is on setting that -- making sure that that market price fully reflects who should bear what risk, given the nature of the transaction, I think that is one that can be mitigated, with some problems.

I mean, I think you can have some kind of procurement process that tries to address the fundamental issue, but you have some residual problems if you think about it in isolation.

Within the context of a competitive procurement process, more generally, that's why I like -- I see that as more of a structural type mitigation to a market foreclosure problem, because it removes kind of the fundamental ability of a market participant to engage in that kind of foreclosure, and some of the incentives.

Once you have that kind of competitive procurement process in place for those daily transactions, where it no longer has the ability or the incentive to favor its own generation on a day-to-day basis, I think that can discipline a lot of the problems that arise in the true interaffiliate transactions where you need some additional bidders in there to provide true market benchmarks.

MR. TIGER: But I might redirect it to IPPs that are distressed in non-RTO markets where you probably have what you've described as monopsony power in certain regions.

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And let's say we were to apply tests that were to fail transactions where utilities want to buy and put in rate base, could you guys play it forward, what's likely to happen, assuming that there aren't structural changes to those markets?

Likely -- and I guess, what's the ultimate competitive result going to be of that? If you assume --

and I'll make a couple of assumptions here -- that a lot of those plants are held by distressed players that are either going to turn them back to the banks if these sales to the utilities don't go forward, or that they'll sell them to vulture investors who will buy them for less than the utility would have, but are not long-term holders, what is the next step and does it really change it?

Should the Commission just say, okay, we won't let the transaction go to the utility and we'll just wait and see what happens later?

I mean, do you guys have thoughts about what's likely to come in that case?

MS. TEZAK: My first question is, what led to the utility being in a position of monopsony power, anyway? That's rhetorical.

Given the fact that that is now the only game in town, the question is whether or not that means that there is a real structural problem with those assets being acquired at a discount, even if by the utility?

And in markets in areas of the country where we don't have RTOs, you have a genuine problem because you have a very, very limited competitive market of any kind.

And so I think what the problem is, is, you know, is it necessary to make a determination on who the buyer is going to be? And is it better to have the vulture investor come in?

It depends on what your policy goal is. The problem is that we still have the state regulators driving procurements of load-serving entities in non-RTO markets, and we still have them driving procurement in RTO markets.

And if they believe that the price offered by an affiliate, which is, you know, offered at book, but is depreciated down from the cost of construction, meets their prudencey bar, I think you're going to wind up in a jurisdictional fight, which is not going to help investment, because we know how that story goes.

And what concerns me most dramatically about the conversation we're having here, is Mr. Hunger's asking about rates. Which rates? Wholesale rates? Retail rates?

If you look at any of these filings that are now pending in front of the Commission, everybody his having this huge discussion about how we're cross-subsidizing to the retail ratepayer. Last time I checked, that wasn't your problem.

If it's happening and it's abusive, it's a problem at the state level, and if you would, if it is your problem, please point me to the statute that says that you guys are in charge of overseeing how states run their procurement programs, because I am worried that if we think we've got a problem now with transmission, if FERC starts setting standards that are inconsistent with the bars that are set for state procurement, we're going to have a problem.

That can be avoided if there's cooperation. That can be avoided if perhaps there's an opportunity to work with states. And this is an initiative that FERC can have to say, hey, there are opportunities in the marketplace that you may not realize are available to you.

But to mandate and drive this, and say we're going to preclude the utility from ever buying an asset that happens to be on sale, is a fight, I will tell you, investors will not welcome.

MR. O'NEILL: What's the difference between the utility buying the asset, put it in rate base, and operating it, versus getting what I would call maybe a distressed long-term PPA where the original investor could operate the utility and possibly benefit by efficiencies that you can't gain in rate base?

MS. TEZAK: Well, I think that as far as its impact on the market as a whole, there is no difference.

MR. O'NEILL: There is no difference, so you think a vertically-integrated utility with an asset in rate base would efficiently operate the power plant as well as an independent power producer with a long-term contract?

MS. TEZAK: Is efficiency what we're regulating?

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MR. O'NEILL: That's a goal. Or you don't believe in efficiency as a goal?

MS. TEZAK: I do, but if what we're looking at is whether or not it's appropriate for one entity to own an asset over the other, I don't understand how then, if I happen to be a company, how I prove to you in the affirmative, as utility or otherwise, that I'm an efficient operator.

MR. O'NEILL: Well, there's about 100 years worth of literature that says that the incentives, if the asset is in rate base, are not as great as if it's under a purchase power agreement, to operate the asset efficiently.

MS. TEZAK: And the ultimate customer is who?

MR. O'NEILL: The ultimate customer of what?

MS. TEZAK: Is a retail ratepayer, correct?

MR. O'NEILL: Yeah.

MS. TEZAK: And the oversight of whether or not the procurement for that retail ratepayer is efficient, belongs to whom?

MR. O'NEILL: The oversight?

MS. TEZAK: Um-hmm.

MR. O'NEILL: The state commissions, but we also have an oversight role.

MS. TEZAK: Right, when those assets participate in the wholesale market.

MR. HUNGER: Just another point of clarification: We had Dr. Hilke earlier talk about and Diana talk about the long-run inefficiencies associated with regulatory evasion. And we were talking about long-run inefficiencies which would affect the wholesale market, which is under this Commission's jurisdiction, so there is a connection there.

It's not that this Commission is trying to --

MS. TEZAK: I don't deny that there is a connection, but I'm worried that the direction that the conversation is going, is going to put us on another one of these collision courses, and that's my point.

I don't disagree that there are wholesale market implications, but what is astonishing to me is that when you read through these dockets and you read through the interventions and you read through the allegations of cross-subsidization, these are issues that are already -- that can be protested and addressed through other existing programs here at the Commission.

There are affiliate abuse standards, there is cross-subsidization under PUCA, still, and theoretically, we've got two different regulatory agencies overseeing the prevention of this problem and it still exists.

What I am not convinced about is that contorting this particular process any further, solves any of those problems, if we're not -- as Mr. Cooper said, if we're not enforcing the laws we've got on the books.

MS. MOSS: Sorry, Christine. These are competitive issues. These are wholesale competitive issues that this Commission has full jurisdiction over.

This Commission is charged with promoting competition in wholesale markets. That means no harm to competition and no harm to consumers.

I mean, you know, a lot of it depends on what perspective you come to the table with here, but I view these squarely as competitive issues. And if they are not properly identified and addressed and remedied on a case-specific basis--I'm not talking about sort of blanket remedy here; it should all be done on a case-specific basis using good, you know, the benefit of experience and the particulars of each situation--it has a direct impact on competition and efficiency, so maybe I'm not seeing part of the argument here, but I see a direct connection.

Now, I agree and I think we all agree that there's a lot of entanglement between wholesale and retail. And there is an increasing encroachment -- well, maybe "encroachment" is not a good word -- but there is an intertwining, now more than ever, in wholesale and retail, and I think that's a challenge that the Commission is going to have to meet.

MR. COOPER: I wanted to get back to original question. Vultures never build anything, and that's why they're defined as such. So, I don't know what good they do me.

They're a short-term solution, but eventually when they have to step up to the plate, they're not going to invest capital on a dollar-for-dollar basis. We have a wonderful -- the broad band world is filled with people who bought networks on a penny on the dollar, and they'll run them until they get filled and they assume they never have to expand them.

But the long-term solution, the long-term answer that you asked for was -- and someone used the term, "preferential access to utility finance." It's remarkable how attractive preferential access is to utility finance. Utility finance benefitted consumers mightily for an awfully long time, as far as I can tell.

MR. O'NEILL: In the nuclear industry?

MR. COOPER: Well, not in the nuclear industry, and the answer was that one of the reasons we liked competitive bidding was because it would take the decisions away from regulators, but we've leaned that bad markets actually do more harm than bad regulators.

MS. SIMLER: This has been a very productive dialogue, and with ten minutes to go, I was wondering if we should open it up to the panelists from the earlier session and to anybody in the audience who might want to ask a question?

(No response.)

MS. SIMLER: Okay, well, then I've got an announcement: The Commission is going to be taking comments on the conference from this morning and this afternoon's conference. They will allow a 21-day comment period, so I'd like to encourage everyone to file comments.

I found this to be very productive. I'm hoping that in your comments, you can take it to the next level and come back with some additional solutions for us and things for us to consider and think about.

And if anybody up here has anything --

(No response.)

MS. SIMLER: We're good? Okay, then, I think we'd like to wrap things up. And, again, I appreciate everyone's time and involvement and thank you.

(Whereupon, at 3:51 p.m., the technical conference was concluded.)